INTEGRATED ENERGY POLICY REPORT (IEPR) UPDATE

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

In the Matter of:	)	
	)	
Informal Proceedings and	)	Docket No.
Preparation of the 2004 Integrated	)	03-IEP-01
Energy Policy Report (IEPR) Update	)	03-RPS-1078
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CALIFORNIA ENERGY COMMISSION

1516 NINTH STREET

HEARING ROOM A

SACRAMENTO, CALIFORNIA

TUESDAY, MAY 4, 2004

10:08 A.M.

Reported by:
Alan Meade
Contract No. 150-01-005

COMMISSIONERS PRESENT

John Geesman, Presiding Member

James Boyd, Associate Member

ADVISORS PRESENT

Melissa Jones

STAFF PRESENT

Marwan Masri

ALSO PRESENT

Steven Kelly, Policy Director
Independent Energy Producers

Joseph Henri, Director
Pacific Gas and Electric

Stephen Probyn, President and CEO
Clean Power

Les Guliasi, Director State Agency Relations
Pacific Gas and Electric

Gregory P. Morris, Ph.D., Director
Green Power Institute

Daniel N. Schochet, Vice President
ORMAT

H.I. Bud Beebe, Regulatory Affairs Coordinator
SMUD

Mark J. Skouronski, California Business Development
SOLARGENIX ENERGY

Manuel Alvarez, Director Strategic Policy and Regulation Regulatory Affairs
Southern California Edison

ALSO PRESENT

Joseph Kloberdanz, Manager Electric Case Management
SDG & E

David Arthur, Ph.D., Energy Supply and Marketing
Redding Electric Utility

Anders Glader, Renewable Business Development
PPM Energy, A ScottishPower Company

Philip Rudnick
Southfork Ranch

Frank W. Harris, Ph.D., Regulatory Economist
Southern California Edison

Karl E. Knapp, Ph.D., Senior Resources Planner
City of Palo Alto

Jerry Jordan, Executive Director
California Municipal Utilities Association

John Berlin, Member Services Coordinator
NCPA

Jim Woodruff
Southern California Edison

Stephen Heckeroth

P R O C E E D I N G S

10:08 a.m.

PRESIDING MEMBER GEESMAN: Let's come to order. This is a committee workshop for the Energy Commission's 2004 update of the Integrated Energy Policy Report which we adopted last fall. I'm John Geesman, the Presiding Member of the Commission's IEPR Committee. To my left is Commissioner Jim Boyd, the Associate Member, and also the Presiding Member from the '03 Report. To my right is Melissa Jones, my Staff Advisor.

Today's workshop is the first formal event in the update process that is focused on renewable energy development. We've got several goals for the workshop that are outlined in the notice.

One is to explore the renewable portfolio standard goals beyond 2010. The second is to consider the possible re-calibration of specific utility goals under the RPS Program. The third is to discuss the RPS Program as it applies to municipally-owned electric utilities. The fourth is to discuss issues related to the use of tradeable renewable energy certificates.

Commissioner Boyd, do you have anything

that you would care to say?

COMMISSIONER BOYD: No, I think it is my pleasure to be part of this process building on last year. I said, no, and then I start off on a lecture, but I look forward to the output from today, and I look forward to the Commission being able to move this subject down the road. I really look forward to people being very forthcoming on the subject with us today. Thank you.

PRESIDING MEMBER GEESMAN: Sandra.

MS. FROMM: Good morning, I'm Sandra Fromm, the Assistant Project Manager for the Integrated Energy Policy Report. I would like to welcome you here today and thank you for your participation in this workshop.

I'd like to go over a few logistics and then turn the workshop over to Tim Tutt of the Renewable Staff. Today's workshop will be a round table format, and if you are speaking today if you could provide the court report with a business card or your name, that would be appreciated. It would help him get the information into the record correctly.

When making presentations, you need to speak very close to the microphone. They are a

little bit sensitive. The workshop will begin with an overview by Tim Tutt, followed by any comments or presentations by interested parties.

After the presentations, the round tables will begin. Each round table will be followed by a short break so that we can accommodate any seating changes. There are name tags available on the table so you can fill those out when you come up to the table.

The restrooms, drinking fountain, and telephones are located outside to the left of the hearing room door. There are additional restrooms located beyond the guard's desk, and she can point you in the direction of those.

There is a snack bar and lunch shop up on the second floor, and there is seating up there. There are also some lunch places available within walking distance. With that, I'm going to turn the workshop over to Tim Tutt.

MR. TUTT: Thank you, Sandra. Welcome everybody. I'll get along with my presentation here. I would note that on the agenda, there are no times. We'll sort of take an appropriate break for lunch when it seems like the right time and everyone is hungry. Maybe we will even be done by

then, who knows. I hope not because we have a lot to talk about.

The agenda today, as Sandra mentioned, is to have the staff presentation here and then other presentations. I would add general comments before we get into the round tables. I would like to try to minimize the amount of general comments, the type of coming up to the podium and saying this is what we think because I want to get into that in the round tables when we really address the specific issues.

If you really do have general comments, please feel free after the presentations to suggest that you do, but if you can save your comments to the round tables, we will be going around and giving you an opportunity to talk during those round tables.

As Sandra said, we are going to have three round tables, and we will have breaks for seating changes, and then we will adjourn.

Why are we talking about Accelerated RPS goals? It is has been a topic of discussion over the last year in a variety of forums. The 2003 Energy Action Plan, the 2003 Integrated Energy Policy Report talked about accelerating the RPS to

2010. The Energy Policy Report recommended more ambitious, longer term goals for post 2010.

So, that is what we are here today to talk about is what do we do after we achieve the 2010 20 percent goal. How do we go forward from there? Governor Schwarzenegger has suggested as well in a recent press release with Governor Richardson of New Mexico that there would be a significant goal of 30,000 MW of clean energy in the West by 2015.

This chart shows you historical renewable generation and what the accelerated 20 percent by 2010 target means. We drafted this chart to show that getting the 20 percent by 2010 and then holding at 20 percent through 2017, and it would go beyond that obviously under the law.

It shows you that there is a knee here in the Chart of Renewable Development which we are talking about going beyond or doing something other than simply going up further as a part of a potential policy in the future.

The question is, should we pursue these additional renewables and development beyond 2010? What is the public policy here that we should address and brainstorm about in this workshop?

What are the benefits and the barriers? These are some of the questions we asked in the workshop notice. How and when should the accelerated goals be accomplished, and how do we adjust these goals due to transmission and resource availability and/or cost changes?

Just as an example of whether this goal is feasible, again, this is from the Renewable Resources Development Report information, the 20 percent by 2010 goal equals about 55,000 GWh a year in California, depending on what retail sales actually end up being in 2010.

Our estimated technical potential inside California right now is 262,000 GWh, so, we have a significant additional potential that could be addressed by an accelerated goal.

I would note also that the potential for other WECC states is significantly higher, there is just significant renewable resources in the WECC that has not yet been developed.

What other benefits and barriers? I've listed a few with question marks here, just to suggest that it's not that we've definitely identified these as benefits and barriers, but I want to brainstorm about these today and get other

parties opinions about what they are.

One benefit would be increased diversity and reduced reliance on natural gas. There are studies that show that by increasing renewables, reducing reliance on natural gas, increasing the diversity in the system, you tend to have benefits in natural gas price and security of the system.

Environmental and contribution of climate change goals, another benefit of increasing renewables. There are certainly one would guess some environmental benefits from increasing renewables. The Western Regional Air Partnership talks about reducing haze in the Grand Canyon through a renewable goal in the West.

A variety of other climate change goals are being fully addressed in a three-state effort on the West Coast here, so renewables can contribute to these goals.

Barriers. Obviously, there are some transmission siting and cost barriers if there are remotely situated renewables and significant potential does tend to be remotely situated where transmission would have to be built to those resource potentials.

There are some issues with intermittency

of some renewables and integration of renewables into the system. It is going to be a topic of some discussion in the PUC's RPS proceedings, least cost/best fit, work on the integration costs for renewables. The Commission adopted a few months ago an Integration Cost Report for Renewables which is intended to be used in the first solicitation for the RPS.

The issue of intermittency as we increase the share of the intermittent type of renewables will be fully addressed and explored I believe in 2005 and other IEPR and other policy proceedings as we move forward.

Resource costs and renewable resource costs. One question would be what is the trade off between the cost of achieving the low hanging fruit, the first renewable is the cheapest versus technological advancement making more renewables available, making the resources cheaper as we move out into the future.

How and when should the accelerated goals be accomplished? An example of when showed up as a potential goal in recent legislation that was a goal of 33 percent by 2020. That is no longer in the bill, but it is someone's concept of

how we might or what goal we might establish to go beyond 20 percent by 2010 was also a campaign plank in Governor Schwarzenegger's campaign before he was elected.

Examples of how. There is a combination of mandate and incentive that is one possible path. It is sort of how the current RPS works. There is a mandate, but it is supported by incentive funding in the form of supplemental energy payments.

Incentives beyond the current mandate, are there other ways of providing incentives to go beyond 20 percent, either in a specific utility or entity or state-wide. What else could be done to provide incentives to convince entities to procure renewables beyond the 20 percent target that we currently have in the policy in California?

Another question is what adjustments, how do we go forward and adjust the targets and the goals we have to reflect market conditions as they change? What kind of legislative and regulatory flexibility do we need to reflect what we learn as we move forward in terms of the cost of renewables and the costs of the alternatives and the available development of renewables in

future years?

Another topic that we raised in the workshop is re-calibration of utility goals. Right now the RPS is a Renewable Portfolio Standard where each obligated entity is required to get 20 percent of its retail sales, and the policy is by 2010.

Some of the rules haven't been developed for some entities, but the expectation that each obligated entity, the rules will be developed, they will get the 20 percent, and the policy is by 2010.

Now should those targets differ by utility seller or remain equal state wide, there are potential reasons to consider, to think about why they might differ by a particular retail seller, that the potential would be higher potentially in a particular area. Circumstances of an entity might lead to a much more difficult accomplishment of that standard for that entity, etc.

How do we account for the varying resources within each utility area and varying transmission infrastructure, resource development costs? If we establish these different targets

for these utilities, should they be incentives above and beyond a standard mandate for everyone, or should there be differential mandates for these obligated entities?

This chart gives you a picture. It may not be absolute GWh current numbers because there are constant changes and additions to what the utilities and other entities are procuring with renewables right now, but it shows with our current renewable policy of 20 percent of retail sales by 2010, Southern California Edison at this point in time is fairly close to achieving that goal.

This is I think 2003 numbers, so by adding some additional resources in 2004, Edison has made the claim that they are at 20 percent or will be very soon.

That would imply that their obligation to get the 20 percent by 2010 is really maintaining that number for the next five years. PG& E and San Diego and other entities are in different position. Some have significant additional procurement to go.

San Diego obviously has made significant purchases in the initial procurement

and is moving forward very well on their goal. This is the way it currently looks with our current standard. Now just as a hypothetical, let's look at what would happen if we were looking at 20 percent of the renewable potential by location. In other words, look at the potential renewable resources in each area, and what would the obligation be for each entity if they had to achieve 20 percent of that potential.

If you look at this, in fact, PG & E looks fairly close to achieving their obligation under this standard, where as SCE and LADWP and other Southern utilities would appear to have a way to go. This data I think is from 2001, actually, so it doesn't have the San Diego recent procurement in it, but I think it would indicate that San Diego has come close or is in good shape in comparison to this potential goal.

Statewide is pretty similar to the 20 percent of the retail sales goal. You can see the blue chart, sort of the sky blue bar is 20 percent of renewable potential, the turquoise bar is 20 percent of renewable sales, so they are actually fairly close. It is a bit of a coincidence.

There are some issues, I think, with

this kind of target. The renewable potential is an estimated number. It is not measured like retail sales. So, significant changes are possible, as estimates are updated and technology changes. One example is, I think, our technology potential estimates that I showed you earlier don't contain potential for low wind speed resources. Now as technology improves, those low wind speed resources might actually have significant achievable potential.

Another example is the potential that we showed earlier has a -- there's a lot of disparity between various estimates of the potential for solar. Obviously, the sun shines everywhere in California and in many places. How much of that land area could you use, there is a lot of variation in how you calculate the potential for solar, what criteria you use to cut down on the land area that would be used as a gathering area for that solar energy.

We have been fairly conservative in our estimates of solar in comparison to some others. So, there might be some changes in their potential estimates, and that makes it kind of unclear when your obligation is accomplished. You might say

you are at your obligation, you've met with your purchases a particular percentage of potential, and then the estimates change, and then you are no longer at your obligation.

There are probably ways to handle that particular uncertainty, but it is an issue I want everyone to think about and talk about perhaps. Again, in relation to out of state or service area resources, Edison and others currently purchased a significant amount of renewables from out of their service area, from IID, even from up in Northern California. Certainly the RPS in California envisions the possibility of out of state resources being a part of the picture here.

State law allows that under certain circumstances. So, if the procurement of these entities is comprised of a significant amount of out of service area resources, then how does that really relate logically to potential in the service area? That is a question we should think about as we move forward in this accelerated renewable resources area.

Then again, the resource potential in the service area may be a fairly high cost resource. Some might have a lot of potential for

wind, which is generally considered low cost on a energy basis and might have a different integration cost. Others might have potential for more expensive renewables. Should the costs of the resources that are a part of the potential in a service area be taken into account as we look at this potential target.

Just as an illustration and thinking about how you might look at all those different factors and it is a difficult job, you might come to a picture where the renewable generation in each entity compared to the cost of achieving an equal cost target or equal cost burden, would lead every entity needing to do some amount of development within their service area to make the costs equal.

It is a difficult complicated analysis. There is differential renewable resource costs and benefits for service area potential. How do you identify those, what kind of modeling or assumptions do you use there? Differential conventional power costs in each area and an obvious potential for different differential rate impacts in each service area if you move to this equal cost issues.

Not that some of these issues aren't also included or a part of the current RPS target. There are those differential benefits and costs with the current target as well.

Publicly-owned utilities is another topic today in our proceeding, our workshop. AB 1890 long ago, we all remember that, did require public-owned electric utilities to establish non-bypassable usage based charge to fund a variety of public purposed programs, as we know.

SB 1078 required a governing body of a local publicly-owned electric utility to be responsible for implementing and enforcing a renewable portfolio standard. We received information from some of the public utility representatives about how each publicly owned utility is progressing towards that legislative goal.

These entities shall report to their customers their results and progress towards achieving these goals, and what they are doing, and their expenditures of public goods for renewable energy.

AB 1890 obviously of course applied to IOU's and also required a similar charge for

publicly owned utilities, but less direction as to how that charge should be divided among these four categories, and what kind of expenditures the publicly owned would be asked or required to make towards renewable resources.

SB 1078 also indicated that the resources mix by fuel type with separate categories -- that the public utilities were supposed to report the resource mix by fuel type with separate categories for those fuels considered eligible renewable energy resources as defined by Section 399.12. So, they are supposed to report what percentage of their resource portfolio is comprised of renewables under the same definition as applies to the IOU's and the ESP's and CCA's under the main part of SB 1078.

They obviously are free to report additional categories of fuel types if they wish, but they do have to separate out this portion.

One of the questions we have as we move forward in this proceeding are several of the questions is what progress have POU's made in developing our RPS plans? What implementation rules will they use? How do we coordinate POU procurement and transmission planning with

statewide goals? There is a clear sort of a question and has been outside of renewables and outside of this accelerated renewable process of understanding a statewide transmission planning effort as opposed to an IOU specific or service area specific transmission issues.

How do we factor in the POU green pricing programs should those renewable resources procured for those green pricing programs be counted to cover the overall obligation for the POU's for all of their retail sales, and what are the barriers for accelerated RPS targets beyond 2010 for the POU's and beyond 20 percent?

Moving again to another topic on the agenda today is REC's. Renewable energy certificates basically are the environmental attributes that are derived from production of renewable energy.

The electricity production from renewable energy can be separated into two commodities, the environmental attributes, the commodity electricity, and we typically think of the environmental attributes as represented by renewable energy certificate. There is a question in the RPS anyway whether those renewable energy

certificates can be traded separately from the underlying energy.

As I said, current RPS implementation rules require transactions to bundle energy and the certificates from the renewable energy. Changes in law that are being proposed would tend to relax this requirement to some degree, and clearly, it is a topic of proceedings at both the PUC and the Energy Commission trying to understand how trading these renewable energy certificates can be part of the RPS and what the issues are.

We are developing under SB 1078, the Energy Commission is developing accounting system that is based on renewable energy certificates. The accounting system is not a trading platform, it is a way of tracking renewable energy generation by certificates.

The fact that the certificates are there in the accounting system will accommodate and allow market trading of those certificates for purposes for which that is allowable.

The current system we are using is an interim system with a power source disclosure program forms as an underlying basis. The final electronic system is going to be this REC based

accounting system. It is going to be an electronic kind of banking system using certificates as the currency in effect.

There is a voluntary REC market in California. In fact, there are REC markets, those of you who know about in more detail about REC markets and REC trading around the world and the country, there's REC markets all over the place.

The City of Palo Alto Utilities Green Pricing Program is based on acquiring REC's. The Lundberg Family Farms greens up some of their production using REC's as a method to associate their electricity consumption with renewable attributes.

As I said, REC marketers are selling California REC's nation-wide and other places and there's a possibility of buying REC's from outside of California as well.

Why tradeable REC's? As a hypothesis, and not necessarily a conclusion at this point, tradeable REC's could produce least cost/best fit concerns, reduce transmission costs and re-marketing costs.

The kind of implicit in flexible compliance because banking of a particular amount

of renewable energy that an entity procures in one year, is effectively taking the attribute and associating it with the next year's energy. There is that implicit trading or transfer of the renewable attributes in that banking operation.

Again, the REC's could potentially, again, facilitate participation by intermittent resources by allowing the attributes to be separated off from the exact timing of when the generation occurs.

What are the issues with tradeable REC's for the RPS compliance purposes in California? Two that come to my mind are really the relation to the market price reference structure that's being set up in California.

As a slight background for that, the market price reference is supposed to be developed as the all in, long term fixed price cost of the alternative resource. Let's say, a base load resource. Then supplemental energy payments are paid for renewable costs above that applicable market price reference.

For REC only transaction, what market price reference should be used if any? There really isn't a long term fixed price all end cost

for whatever goes along with a REC only transaction.

REC's without long-term bundled energy then could be ineligible for supplemental energy payments. That might be one way to handle this problem that has been suggested in recent legislation, that is a structure that might work, recent proposed legislation.

Another question that policy makers have been struggling with is the PGC contribution that goes into developments of renewables. If there is a PGC contribution, who owns the REC's? If there is a higher, a public component to purchasing or setting up the energy for REC's, do the public or rate payers or private purchaser, actually own the REC, or is the ownership split in some fashion could get to be a complicated issue.

Just as an end slide because I am done with my presentation, I'm going to put in a plug, again, for a tracking system. The green area over here's the WECC, that's the area for which we are developing the WREGIS Tracking System.

There are other tracking systems developed around the country. Texas has one named ERCOT. NEPOOL has one. Wisconsin has a tracking

system, and there are tracking systems being proposed or discussed in PJM and here in this area of the North American continent as well.

That is the end of my presentation. I'm sure that we will get into discussion of these concepts and these ideas as we move into the round tables. There is at least one other presentation that is loaded on this computer, and I will try to get to that and invite Steve Probyn up to do his presentation.

MR. PROBYN: Where do you want me to hang out?

MR. TUTT: Steve, it is best if you stand back here just because the mike will pick up your voice best. There you go.

MR. PROBYN: Thank you. Thank you very much for having this hearing, Commissioners. We are delighted to be here, and I think it is extremely timely. I would just like to talk a little bit about who we are and give you some idea of what Clean Power is as a company as opposed to Clean Power as a concept.

Our company is 100 percent renewable focused in terms of generation. It is actually head office in Canada, but the bulk of the assets

are in the United States. Our U.S. head office is in Livermore.

We are I think probably the only publicly listed stock that you can buy which is 100 percent exposure to renewables. It is widely held. The structure is somewhat like for those people who are familiar with real estate investment trusts, so it pays out dividends, in this case about 10 percent per annum based on its businesses.

We are obviously committed to an environmental business model. We take very seriously the commitment to greenhouse gas reduction. Last year our reductions from our activities equaled about 6 million tons. I think that is around 1.8 million automobiles worth of greenhouse gas reduction.

Our subsidiary, Gas Recovery Systems, I am also here to speak on their behalf, is the second largest landfill gas generator in the United States with some 29 plants.

There you can see a schematic which maps our plants. I like to say we range from the Yukon to Southern California, or in terms of our geographic spread, but I think the more important

message of this slide, is that we are involved as a renewable energy company in all the major North American renewable markets. We feel that this does give us at least a basis for comparison, and we are trying to draw some lessons, which I would like to share with you.

We are very strong believers in REC trading systems. We think it allows the utilities who are subject to RPS requirements to precisely match their obligations and tailor the structure of the contracts that they undertake to meet their obligations on least cost basis.

It is generally relatively neutral in terms of technology. Obviously they are specified. I think another thing that really stems out of the really the staff overview is it does provide a mechanism for dealing with some of the imbalances, the regional imbalances, and I will talk a bit about that in a second.

We think that WREGIS is an extremely important step. We've been very involved in compliance markets in New England, and we have seen the very positive impact that a strong generation information system with a high degree of integrity can have in moving WREGIS towards

their RPS goals.

The way we've seen, and I'm really trying to address, Commissioner, some of the questions you raised. Tradeable REC systems typically use either it's called a price cap or a penalty charge for customer cost ability, also as a compliance mechanism instead of the market price reference.

These have been set oddly enough roughly the same price. There is this sort of general consensus on five cents a kilowatt hour. I mean we've got that here with the current reference, but we've also got in Massachusetts a five cent penalty charge for failure to achieve REC goals. It is five and a half cents in Connecticut. Texas a similar amount, although the trading price in Texas is far less than that number.

That then really provides the basis. The number I think you used the word coincidentally, well it sort of coincidentally does provide a strong incentive combined with a reference that is approaching today's cost in terms of renewables.

So, trading systems simple supply and demand sets the prices for the REC's, and that obviously creates market signals that developers

respond to and increase supply.

In fact, you can see that in the various REC trading systems. It is really the fundamental elegance of the system is that the participants, the market participants, the utilities, load serving entities, and the generators as well as the providers of transmission, are all involved in a voluntary transaction to try and achieve a basic social goal.

I think they can accommodate public benefit programs through the contractual arrangements. Again, it gets back to the contractual arrangements. The granting bodies, for example, as is the case in California, can simply say well, to the extent that you want to avail yourselves, Mr. Generator, of that benefit, then you have to really sign the REC's over to us.

One of the defining characteristics of successful trading systems is typically the REC's are the environmental benefit. The total package of benefits are a unique certificate, and so when that certificate is sold by one of our companies to a buyer, then that is it. Then we have sold the environmental attributes to that megawatt hour of power.

Again, it provides an elegant solution. Voluntary program pricing, the same thing. When a consumer buys green power, that consumer should also get the REC. In fact, that is one of the principles say behind the Austin Energy Program in Texas, which is America's most successful green power program is the principle that the Austin rate payers who buy green power from that program are actually also -- well, they are buying the REC. That is a very important principle.

That brings me to my final point, which is really the question of REC ownership. I think it is very clear that REC's are the property rights of the generators. In fact, I think that is enshrined in the Cavanta Decision by FERC. Unless the REC's are transferred by contract, and as I have specified, SEP type programs can in fact incorporate and do incorporate the transfer of REC ownership, so this isn't an issue in terms of public benefit. They belong to the generator.

That enables generators actually to participate innovatively and imaginatively in renewable energy markets. For example, generators can use proceeds from forward REC sales to underwrite some of their investment costs.

This will enable the provision of renewable power on the basis of for example merchant plants selling power, merchant power into the system through the ISO, but selling the REC's across state.

It also provides much more flexibility. Again, a point raised, the question of geographic flexibility. Renewable power is geographically based. It is windy in some parts of the state, it is not windy in other parts of the state.

A REC trading system enables all utilities to have equal access to renewable resources because in effect they are buying green attributes, the power may be sold in another market that is proximate to the renewable resource.

I would also point out that because of the intermittent nature of renewables and also the small size of many renewable projects, a REC trading program is a much more efficient and cost effective solution for generators. They are able to sell the REC's to the people who want to buy the REC's, and then if for example they are an imbedded situation in a local utility, just sell the power to the local utility without scheduling

through an ISO.

There is a whole bunch of generator advantages. I think just to re-capitulate my argument on ownership, I think it is important to realize that this system really only works if the generator owns the REC's because otherwise the generator has no incentive to participate.

Secondly, it is important to say that the developer is generally assumes the cost of the development and the risks thereto. Also, has assumed the burdens historically of environmental compliance. Obviously, green power must be environmentally compliant as a first step.

So, again, I go back to the point, the benefits should accrue to the generator. So, I would say, however, we are concerned that some suggestions are that the generators may not own the REC's, and I think that would be a barrier to moving forward.

First of all, it would not enable generators to realize the benefits of REC ownership, and in fact, the participation that I have described in trading systems. It would obviously create an investment chill for the development of renewables because there would be

uncertainty about one of the very important property attributes.

It has issues under wider laws both in terms of US provisions regarding property ownership and even possibly NAFTA. So, I think in conclusion, I would say I'd like to just deliver two messages.

One is that I think a tradeable REC platform is an important energy solution, renewable energy solution for this state. I think it will bring enormous benefits in terms of efficiency and hence lower cost to the consumer.

The second key message of course is that when we deal with these issues, I think we must deal with the issues of all affected parties and all stakeholders, ranging from the public, the utilities, but very importantly including the rights of the property owners, the generators in terms of reaching this overall trading framework.

Thank you very much.

PRESIDING MEMBER GEESMAN: I need to ask you a question about that last bullet, though. You're concerned about suggestions that California regulators may expropriate. Which California regulator are you concerned about?

MR. PROBYN: I'm not concerned, of course, that the Commission would.

PRESIDING MEMBER GEESMAN: The California Energy Commission wouldn't.

MR. PROBYN: Yeah, I think the issue really is one that is in the public debate more than has been suggested by regulators that some how the REC's should be taken by the new system without regard to the existing property owners. That is really my concern. I wanted to flag that, but I am certainly not suggesting that state policy has been determined on that issue.

PRESIDING MEMBER GEESMAN: Thank you.

MR. TUTT: Does anyone else have a presentation or general comments before we get into round table discussions? I have one presentation that has just been handed to me, and I'm going to try to get it set up here or talk about how we do that, but does anyone else have a presentation or general comments while I am working on that?

As I said, I would encourage you that the comments right now would be kind of general, but we do have an opportunity if we take a break for about 15 minutes to set these tables up I'm

told, so that we can have a better round table discussion.

PRESIDING MEMBER GEESMAN: Why don't we go to the first round table then, and we will take a ten minute break, 11:05 we will reconvene.

(Off the record.)

PRESIDING MEMBER GEESMAN: Why don't we get started again.

MR. TUTT: Would the first round table come up?

MS. FROMM: Would everyone please be seated and let's get started with the first workshop series.

MR. TUTT: Would representatives from the utilities and other interested stakeholders please try to find a seat at the table around, so that we can have a round table discussion on the first issue.

The first round table is addressing the accelerated goals beyond 2010 and re-calibration of utility targets issues, so would people please come up to the table and sit if they are interested in those issues.

There are a couple of more spots over here for people. While we are getting prepared

here, I nearly forgotten Mr. Heckeroth and his presentation. I apologize for that Steve.

Steve, I am expecting that your presentation has something to do with renewable distributed generation in part?

MR. HECKEROTH: That's correct.

MR. TUTT: We will listen to the presentation, but in general, we are concentrating on the larger central renewables in this particular workshop. We tentatively are planning a workshop on June 8 to discuss distributed renewable generation policy issues.

Go ahead, Steve.

MR. HECKEROTH: My name is Steve Heckeroth, for the record. I've been involved in renewable energy since the first Earth Day which happens to coincide with the year 1970 when both oil and gas domestic production peaked, and we started relying on imports.

I think that distributed generation can supplant centralized plants if we allow them to. Wow, that is really sensitive.

MR. TUTT: You said you were going to go really quick, Steve.

MR. HECKEROTH: Yeah, it just freaked

out on me here. I'll try a different way to do it. There I go.

Our governor has made a pledge during his campaign and also during the State of the State to encourage what is called distributed generation, to have 50 percent of new housing developments install solar PV by 2005. That is pretty ambiguous, and as Tim pointed out, 33 percent of the state's power from renewable sources by 2020.

There are a lot of publications recently come out about the looming oil and gas crisis. I pay particular attention to the last one here "High Noon for Natural Gas". It is due to come out next month, and it relates the story of natural gas that is having the same sort of a path as oil.

US oil production, as I said, peaked in 1970, and California currently pays about $80 billion a year to other states and countries for our 80 percent of the fuel we burn.

So, the centralized power plant scenario is going to make us further dependent. At the same time, California is the Middle East of solar power. We could provide all of our energy from

the sun, and actually we do, it is just ancient sunlight that we are using now.

Even with photabletaics, centralized power has a lot of disabilities that requires valuable land, a lot of valuable land. There is reliance on the transmission and distribution and power is valued at the wholesale rate. With distributed generation, there is no additional land required. We used to say that we could supply all our power from solar energy on so many square miles of desert. We don't even have to use square miles of desert, all we have to use is our roofs, and we can supply all of our energy.

My homestead is run entirely off of solar energy, from photabletaics and also I charge my electric vehicles, so it can be done. Power is valued at the retail rate, and solar is naturally peak shaving, which means that about half the electricity is used for pumping water. When we need the water is when the summer is around. So, it is an ideal source for shaving those peaks, and it is also ideal for shaving the cooling needs in the hottest days of the year.

Here are the choices we have. Fossil fuel, of course, burns oxygen which is kind of an

important resources and PV doesn't use any essential resources. We become much more reliant on foreign oil and gas. We are talking about liquified gas stations that are going to be very expensive. BIPV distributed generation requires no additional land, no expensive reclamation of that land, and it also doesn't cause any sickness or death.

The environmental consequences are pretty plain. We hear about them every day as we become more dependent. The infrastructure for fossil fuel is very ugly. It uses a lot of land. PV roofing would only use the roofs that we have already going to waste, and I just hope that we can't make some wise choices. Thanks.

MR. TUTT: Thank you, Steve. As I said, we are planning on looking at distributed generation issues in more detail tentative June 8 workshop. Save the date but don't make your flights yet because sometimes these things change. We will be noticing that in the near future.

Let's get down to the first two topics in our first round table. We are talking about Accelerated RPS goals beyond 2010 as called for in the Energy Action Plan, and at least called for in

terms of looking at that issue. We raised in our Attachment A to the workshop notice a series of questions about this.

The first is, should the state pursue additional renewable development beyond 20 percent of retail sales through either mandates or incentive structures. I was wondering if we could go around the table here and start with you, Joe, if there is something San Diego feels, or do you feel personally about that particular question or the topic in general. Take all of the questions if you want. What does San Diego have to say?

PRESIDING MEMBER GEESMAN: At least on the first round if people would introduce themselves by name and by affiliation, it would help our court reporter.

MR. KLOBERDANZ: Thank you, Joe Kloberdanz with San Diego Gas and Electric. SDG & E received a few kudos during the opening presentation here today. We appreciate that.

I will admit, and it is obvious from some of the charts Tim used, that Mr. Tutt used, that SDG & E probably had the furthest to go among the three IOU's. We intend to meet the goals by the deadline if not sooner. We do have a long way

to go.

As we look at extending those goals beyond 20 percent and beyond 2010, it is probably no news, but I feel like I need to say it, we need to make sure that we have considered what progress we have made on some of the things that we know are in the way right now.

It has been said in this very room many times that we have a problem getting transmission built in California. We applaud the efforts of the PUC, CPUC, and the CEC to work together in at least one proceeding and probably others to try to address that issue.

We need to see how soon and to what extent that effort can bear fruit and weigh that in determining how realistic it is to set goals beyond 20 percent beyond 2010.

We need to get a system of REC's established. That has been mentioned here today, and SDG & E strongly supports that. Those need to be verifiable. They need to be trackable, and they need to become tradeable. We need to get past some of the debates about who owns them and how that ownership shifts. Those are all important things. We need to mark progress on

that and weigh what that progress allows us to do in terms of further goals.

With respect to RFP's themselves, SDG & G has been able to in an interim authority we were given by the PUC, we have been able to get out and get some substantial progress going from our perspective on signing up renewables. But we have yet to conduct, and none of the IOU's have conducted, an RFP under this CPUC's new regime and new set of rules issued last June I believe.

We need to get probably a couple of those under our belt to see how deep the market is, how they can price relevant to the MPR, which the PUC is just now establishing and what that says about our ability again to go beyond 2010 and to go beyond 20 percent. We really need at least a couple of those under our belt.

Now, SDG & E is pursuing RFP's and sustainable communities strategy to try to meet and exceed the renewables goals that have been set for us. We need some time for both of those. The sustainable community strategy is something we have put forward in our cost of service proceeding, that is pending decision hopefully not too many months from that.

Looking ahead to whatever we end up doing beyond 2010 and beyond 20 percent, we like incentives, and we like voluntary efforts. One of the things that we would definitely be looking at is green pricing in that regard.

I think I will stop there for now.

MR. TUTT: Bud, do you have anything to add or any questions of Joe?

MR. BUD BEEBE: No, not really. We are fine here.

MR. TUTT: As Commissioner Geesman suggested, would you please name and affiliation if you were going to say anything.

MR. BEEBE: Yeah, my name is Bud Beebe. I'm with the Sacramento Municipal Utility District, and I'm pleased to be here as a part of this. I think we are all going to learn a lot about what the intentions are and actually how much progress actually has been made to date as we direct our efforts towards attaining the legislated goals. So, I look forward to probably participating mostly in the publicly-owned utility round table, but I have some reflections that I will save till the end on this particular portion as well.

MR. MORRIS: Hi, Greg Morris of the Green Power Institute, and I do have a few remarks I'd like to make on this topic of accelerated RPS goals.

I do consider myself an advocate of renewable energy. When the original RPS program was established just a couple of years ago with a goal of 20 percent by 2017, I considered that actually a pretty aggressive target and not easy to achieve goal.

We have set aside a certain portion of public goods, money to pay the above market cost of renewables in order to achieve that goal, and now we are talking about compressing that goal to achieve compliance by 2010.

I think we have to ask ourselves what's the point in doing that if we don't follow it up with a further goal. We run a great risk of sort of doing what we did in the 80's which is to have this tremendous burst of development activity of renewables followed by a complete bust.

I just don't see that as a very desirable outcome. If we are only going to 20 percent, what real gain do we have by doing it seven years earlier and not putting more money

into it. If we truly want to accelerate it, we ought to have some goal beyond it that is above 20 percent in order to create a kind of a long time progression of a growing and stable renewable energy market. I'm talking about in terms of new installations.

So, that is really my biggest concern is that by accelerating it, we are going to get less technological innovation because we are going to need everything we can get right now as it is. Again, unless we have a higher longer term goal, which will then engender that technological development through the longer run, so I encourage us to think about what those longer term goals should be if we indeed we wish to push this RPS goal of 20 percent up to 2010.

I also think we really need to think about how we are going to fund that because frankly, I would love to say it's easy, renewables are cheap. But that is not true. I mean if renewables were cheap, why would we need SEP's, why would we need to debate it. If it was the cheapest energy source, we would do it for all the right reasons.

So, the new legislations legislative

digest sort of addresses this issue by saying well, gee, so far we haven't dipped into the SEP's because we haven't had a RPS solicitation so we don't know whether the funds are going to be limiting or not.

As we accelerate the goal to 2010, why don't we wait and see whether or not the SEP's are going to cover the goal. I really think we have to think about the fact that if we want to accelerate it, we are going to have to think about accelerating the payments. Otherwise, we are just kidding ourselves, and we may put ourselves into a position where we can't achieve anything at all.

Thank you.

PRESIDING MEMBER GEESMAN: How do we respond, then, to the fact that Edison for some numbers of months now has been telling us that they are there, and they have not yet dipped into one dime of supplemental energy payments?

MR. MORRIS: That's great. I mean, Edison has obviously the easiest path between today and 20 percent whenever it is that 20 percent is mandated to be reached. That is to their credit and to their good fortune. I don't think there is a problem there.

PRESIDING MEMBER GEESMAN: Well, I guess. I'm sorry, go ahead, Manuel.

MR. ALVAREZ: No, go ahead and ask your question, and then I'll follow up.

PRESIDING MEMBER GEESMAN: It strikes me, and I remember, Greg, I think it was a little more than a year ago hearing you tell us how unachievable the 2017 goal was likely to be. Frankly, I think the question of acceleration to 2010, at least within the Executive Branch of government, is water under the bridge or the horse out of the barn because you've got all of the regulatory agencies and the governor saying 2010. That is pretty much a clean sweep as it relates to the Executive Branch.

I agree that there very well may be a necessary funding aspect of that which will require the legislature to concur if additional appropriations are needed, but I think Edison has set a fairly remarkable example. I credit them for picking off whatever low hanging fruit existed there. The fact remains that a goal was set, they appeared to have accomplished it, and they've not yet used one dime of subsidy monies. At least some portion of that must be irreplaceably

experience.

MR. MORRIS: What Edison's achieved, as I understand it today, has really been mostly with existing facilities. There hasn't been any real new development of significant proportion. There has been a little bit of new development that they've purchased from the Geysers. They've purchased from existing facilities for the most part, or correct me if I am wrong.

I think when we get into a large development cycle, that is where the trick will come. Yes, Edison might be at 17 percent, but state wide we are still closer to 10 percent. In fact, the IOU's as a group are ahead of everybody else. The 65 percent of the energy that is distributed by the IOU's is distributing about 80 percent of all the renewables. That means the other 35 percent is well behind.

While Edison is in good position, therefore, and again to their credit, we need everybody to come up to those levels. Otherwise, they are in effect, bearing an unequal burden.

MR. ALVAREZ: I think Greg mentioned, and I think you have to look at what Edison's historical activities were in this area and our

commitment early on to move forward with the RPS and renewable purchases historically. So, I think you need to keep that in context.

I'd like to bring up an issue that I think relates to the goal here if I may. When the goal was set originally, it was predicated on what existed at that time, and that was the public goods charge and what was anticipated to be funded under the public goods charge. So, there is some fundamental basis of at least prescriptive nature in terms of what the amount of renewable generation was going to be.

You know, Tim reminded us of the campaign plank of the 33 percent. From my perspective, there is a lack of foundation for the 33 percent or the 30 percent from an analytical perspective of whether the marketplace or the development of that progress or how it would take place would be met. So, I think that is something that is still lacking for the capability to go ahead and say, okay, it is achievable under this kind of scenario.

We are all aware of the potential and the analysis the Commission did a year ago of what that number looks like. There is far more than

technical potential. You have to deal with a lot of the infrastructure and business development and economic development activities that go along with that.

Thank you.

PRESIDING MEMBER GEESMAN: Manuel, to get back to something else Greg said, you and I went through the state government process in the late 1970's that created the very strong policy that lead Edison and the other utilities to burst of renewable utilization in the 1980's and then nothing else happened.

We, I think, missed some fairly significant opportunities as a state and as a society to build on those earlier successes. I'm not certain that analytic rigor is particular the first criterion in evaluating whether a 2020 goal is desirable or not.

I couldn't tell you whether 33 percent is the right number or 30 percent or 40 percent, but I think stopping at a 2010 goal is a little bit like choosing to try to win the Mr. World body building contest and just giving up thereafter. I think there is a lot to be accomplished by setting aggressive goals for ourselves.

I would really like to know the rationale from any of the participants as to why we shouldn't set some stretch goals for 2020.

MR. MORRIS: If I could respond, Commissioner, because I didn't want to pour too much water on the fire to say, "Don't do 20 percent by 2010." What I am saying is if we are really going to do that, we really ought to follow it up with a larger goal in the longer term.

I don't know either if analytically 33 percent of 2020 is the right answer, but then again we don't know that 20 percent in 2010 is the right answer either. It is somewhat arbitrary. Really what will determine how far we go ultimately is how much we put into it.

Again, if we are going to cause this great burst of development, I think we want to make that a preliminary step to a longer term industry in the state. That is what we will really benefit from.

Also, think about markets penetrating in the so called logistic curve which is sort of the S-shape. You start out a little bit slowly, you go into a very steep period of development, and then you start to peak out although the ultimate

goal will increase over time assuming that we grow as a state, which we certainly seem to be doing.

If you have a longer term goal, you will actually slow down the very initial development of that by giving the market expectation that it has to peak further down the road. I actually brought an overhead, but I don't know that we have an overhead to display conceptually what I mean by that.

Anyway, I think if you look at market dynamics, if we are going to get this industry growing and growing fast, we need to have the long term looked at too, which means to continue beyond -- I mean 2010 is only six years away.

COMMISSIONER BOYD: Greg, if you want to show your overhead, there is such capability over there. While you are doing that, perhaps let me say --

MR. MORRIS: Okay.

COMMISSIONER BOYD: I found interesting your commentary on boom bust cycle and then Commissioner Geesman followed it up with reinforcement. I was concerned a little bit about accelerating the goal less technological development, but I think that is the bust after

the boom and no future incentives. I mean, you have planted some issues that I think are interesting issues. There are some of us who believe in pushing technology as rapidly and as hard as you can, though. That hopefully leads to accelerating technological development. I don't want to get into that today, and I sure don't want to pursue body building.

MR. MORRIS: Indeed, if you follow it up with a longer term goal, then you have that incentive.

COMMISSIONER BOYD: Yeah, I get your point well.

MR. TUTT: I think that, again, going back to what Joe started us off with, there is a foundation that is being laid, and it needs to continue to be laid.

If we do look at a long term more accelerated goals, as Commissioner Geesman suggested. If it is far out and flexible, it is just something to shoot at, and so the foundation can continue to be laid, and the analytical development can continue to determine whether the right number is 33 percent or 30 or something different as we move forward towards that target.

That seems like one way to think about it.

Did you get it, Greg, or is it not going to go?

MR. MORRIS: She's gone to make a phone call, so we should move on then. I'll put it in the comments if we can't get it.

PRESIDING MEMBER GEESMAN: Mark.

MR. SKOURONSKI: Mark Skouronski, Solargenix, following up on the good doctor's comments with respect to continuation past 2010 and the funding of that.

I would like to point out that Edison came out with an interim RPS solicitation, and I read where they got like 5,000 megawatts potential of RPS, half of that is below market.

That represents a potential funding source with respect to RPS because I think the implied intent of SB 1078 is to keep the utilities neutral, to keep them whole. If we do not have an RPS standard, then the rate payers would be paying "X" amount.

With this RPS standard, so far apparently, the rate payers are actually going to be below "X". In other words, the RPS standard is benefitting the rate payer over what they would

have had otherwise.

When we talk about funding, I think we should do this on a balanced account basis. If utilities are coming in low, fine. Then this legislation then has actually saved them money over otherwise what they would have paid for fossil fuel. That is a good source of funding. It keeps everybody neutral. Nothing else has to change.

Secondly, I have a personal projection I guess. I think the last energy crisis cost the state literally billions if not tens of billions in overcharges and penalties and lost production, etc. While we see another generation shortage possibly coming up in 2006/2007, past that I think we can also look at a fossil fuel shortage of some sort.

I look at all the estimates from the CEC and other proprietary gas estimates, so much depends on all these natural gas facilities, excuse me, natural gas liquified facilities coming on line. If they are not on line, I think you are going to have some shortages on gas. The same impact on the California economy of being generation short will manifest itself in being gas

short. A fossil fuel replaced by a renewable portfolio standard gives the state insurance of not over relying on natural gas.

That's all.

MR. SCHOCHET: I'm Dan Schochet, and I'm representing my company ORMAT, and we are a geothermal operator in the State of California. I just have a few brief comments.

First, obviously there should be goals beyond 2010, but accelerating them at this point is I think premature. From a geothermal point of view, one of the problems we face is that -- we, meaning the industry, is that there is approximately a three year development cycle for new geothermal power plants.

With the short time period, it is questionable how many new geothermal projects can come on line, though there could be expansion of existing geothermal projects in California.

The second limiting item for the geothermal industry is that with the hiatus of new development in the 1990's and with the lack of a transparent market, there was no exploration of any kind, so we saw many of the potential developable geothermal resources simply not

explored because the companies were loath to invest funds in this high risk without knowing there was a market.

Now, as far as the market itself and the prices, I have personally been involved in Nevada's RPS, and in attempting to sell the concept of an RPS in several other states, there seems to be a fear of what the market would do. I just want to give you some statistics which I think are born out by some of the Energy Commission's own reports.

For example, for geothermal power plant equipment, in 1985 the cost of a new geothermal power plant, not including the wells or permitting, was between $1,000 and $1,500 a kilowatt hour in 1985 dollars.

In 2004, the same power plant is still between $1,000 and $1,500 a kilowatt, but in 2004 dollars. Which means effectively, the price of implementing a geothermal power plant in real costs is considerably reduced.

In our case, this was reduced because we used the decade of the 90's to develop projects overseas. The result of this is that in Nevada, where the RPS was implemented several years ago,

the market cost or the market price for wholesale geothermal power through the utility for existing projects was in the range of 5 to 5 1/2 cents per kilowatt hour for the first year, with a minimal escalation, usually it is one percent.

The bid prices for such projects from Greenfield was in the order of about six to seven cents per kilowatt hour with a small escalation.

Which means if we look at market price for new projects, and we compare it to risk adjusted fossil fuel prices over the same 20 year horizon, I suspect it would be almost no difference, especially if it were a risk adjusted price as opposed to assuming that the price of gas would stay the same.

My belief is that the market will sort itself out in California as it probably will in Nevada. I believe that the 2010 is a bit ambiguous especially as we view it from the geothermal industry, but certainly looking at goals beyond 2010 is something that should be considered because I think the renewable industry will pick up the slack and begin to put the necessary investments into exploration of development of new geothermal resources.

Thank you.

PRESIDING MEMBER GEESMAN: Thank you. Greg, you've got your chart.

MR. MORRIS: Thank you. I'll go through this real quick.

This chart shows the total market starting in 2004 on the left for renewable energy in California. The straight line I drew at 20 percent and shows it going up because, again, of population growth and so forth.

I've shown in red a development path to it which is 20 percent at 2010 and then remain at 20 percent, and then the blue line is a more likely development path where you would hit 20 percent at 2010, but then go on beyond 20 percent in the longer run. That is what I meant by you would actually decelerate the initial rate of market penetration if you had that expectation of the larger market.

What it shows for new installations, and this is just conceptually drawn as you can well see is that if you accelerate it very fast, but then keep it at 20 percent, you are going to have this burst of activity and then it is going to dip right back down again in terms of new project

development.

If you have the longer term goal following up on the shorter term goal, you have a much better chance to create a more stable development market.

Thank you.

PRESIDING MEMBER GEESMAN: Thank you. Steven?

MR. KELLY: Steven Kelly with the Independent Energy Producers Association, and I am just taken it as a given that we've got a 20 percent standard by 2010.

I'm kind of wrestling with the issue about whether you now accelerate that goal, and that is the purpose of what this workshop is, but quite frankly, I guess I am a little surprised that we are talking about adjusting the goal when we really haven't a procurement on SB 1078.

I think this is the comment that Joe was mentioning. The key to the ability to change this goal is likely to be convincing policy makers that it makes sense, particularly in the legislature.

One of the drivers of that, of course, is going to be the cost of this stuff. We have yet to see a series of procurements that would

tell us what the cost is. Even the ones that have occurred outside of SB 1078 by Edison and others, I believe occurred under AB 57.

It is hard to find out what the cost is, but if the cost of renewables is a cent, we ought to be billing 50 or 60 percent of this stuff. If it is 20 cents, then the goal is going to be a lot less.

The problem that we have now, I think is that we haven't had a series of procurements that would really reveal what the cost is to meet any accelerated goal. I think we really need that. We need a series of procurements.

It is somewhat unfortunate that it will probably almost two years after SB 1078 was passed before we actually have a procurement under that mechanism.

I have often stated my concerns about that bill because of the complexity and so forth, but ultimately what it means is that there is no contracts. The contracts will drive the development schedule to meet the energy requirements of the RPS.

I think one of the things we really need to see is timely procurements. I think the PUC

has indicated and you have indicated you want a procurement this summer. My expectation is we may have one in the fall, early fall. That would be great.

Announcing that there is going to be another one the following year or the next two years to meet the next step up would be helpful for developers to start planning new projects.

The issue as to whether we should accelerate the goal or not -- the decision is ultimately going to be driven by how expensive some of those projects are compared to the alternatives, which is to do nothing.

Real quickly, regarding the second component of this on the re-calibration. One of the best features of SB 1078, I think, was that it was based on a percentage of retail sales. That is measurable. We know what the sale are of the utilities. We can measure the sales to them.

I would really urge you to stay on track on that measure. There is a lot of concerns I have that I have about the RPS system in California, the market price and all that stuff, but one of the really good features of that bill is that it was based on a percentage of sales of

each load serving entity.

That is something that is measurable that we can track and follow, and I think it is a very good way to calibrate the program.

MR. PROBYN: Steve Probyn, Clean Power.

Just briefly on the issue of low hanging fruit versus advancement of technology. I think it is very important for us to realize that those two are actually complimentary concepts that increased activity has driven down technology costs significantly.

Wind power, for example, the introduction of the larger turbines by folks such as General Electric have increased availability on a site basis from say the mid 30's to the high 30's or low 40's simply through the implementation of the new technology.

That increases reliability, reduces costs. We have seen that trend throughout not only wind but other technologies such as landfill gas where we've had increased efficiency in the equipment both in the gas turbines and also in some of the recent engines, for instance those recently introduced by Caterpillar.

So, I think costs are coming down

significantly, and I think in a good site today, our experience is that the costs are for renewables for wind would be below that of fossil fuel gas generation in California.

Obviously, that begs the question, so, why bother having an RPS? The answer is that there are other barriers that are institutional in nature that the RPS breaks down, that it has created this incentive for utilities to look at the source of generation. They have responded very well, as we've seen.

We need to deal with transmission and siting issues, and we need to deal with them. The RPS forces us to move forward on a pace. That really brings me to my conclusion, which I think, Commissioner Geesman, your idea of stretch goals are important, and that stretch goals will be realized, and they will likely be realized without SEP-type subsidies to renewable energy. That has been the experience.

I think the Edison experience is just unbelievably instructive in terms of both the magnitude of the response, 5,000 megawatts, and the cost of those resources. I think that is a very important lesson for us to take back in terms

of the design of the future standard and to realize that we can afford stretch goals without bankrupting the ratepayer or the taxpayer.

PRESIDING MEMBER GEESMAN: Thank you. Les.

MR. GULIASI: Good morning, Les Guliasi with PG & E.

I appeared before you a couple of times and talked about the renewable portfolio standard goals here and in context of the energy action plan, so some of my remarks you'll find familiar.

We fully support the current legislative mandate for the RPS goal. Since the passage of SB 1078, we've been making steady progress toward meeting that goal.

If you look at our overall resource mix and place the RPS goal in context, you will find that we rely fossil generation significantly less than 50 percent of our total resource mix now.

I think Tim did a very good job of outlining the issues and his bar charts showed accurately that we are by the end of this year going to be at about 13 percent total renewables in our portfolio.

These statistics, let me remind

everybody, represent or reflect only eligible renewable resources. We have a vast hydro system, much of that hydro power is not considered an eligible renewable resource. In some people's minds, it is an important renewable resource.

We have about 19 percent of our power from large hydro and only about 4 percent from small hydro.

In terms of our overall resource mix, that is a very large percentage that is a renewable resource.

I just want to remind everybody that prior to AB 1890 and the divestiture of our power plants, we had an even larger percentage of our resources from renewable energy. The geysers, the geothermal power plants, which were divested contributed about 17 percent prior to AB 1890 to our overall resource mix.

So, you can see over time that because of regulatory and legislative mandates, that number has changed significantly.

In my previous appearances, I've supported the pursuit of the RPS goal, but sometimes to your dismay I've expressed a cautionary tone. The main message that I have

tried to deliver before and perhaps again today is just to take it slow. We need to work on some of the immediate tasks that we have before us.

We put a program in place. We need to pay attention to what we need to do to make that current system work.

Just to outline a couple of those things. To the extent that we are going to rely on subsidies, supplemental payments, we need to make sure that we have adequate funds. We need to make sure those funds are allocated fairly and equitably, and in an orderly manner.

We talked a little bit before in Tim's presentation about the REC System. We have an accounting system going into place, and we need to develop a platform for a trading system. Those are some of the other things that need to be done.

The real key here is that we have a the benefit of a little bit of time on our hands. As Steve Kelly just mentioned, the utilities will be soliciting renewable resources as early as this summer, perhaps in July, and I think we will learn a lot from that solicitation. We will find out what the costs are. We will find out what the profiles are, what kind of power will be offered,

how it will be dispatched, how it will fit into our overall low profile.

We will find out what kind of diversity we will have in the offers, how much wind, how much solar, etc.

Commissioner Geesman, you raised the question about shouldn't the state or policy makers set stretch goals, and I believe in principle, yes, indeed, we should have stretch goals. But, we do have the benefit of time. We are not at 2010 yet.

Let me also remind you that as every year goes by, we will be renewing current contracts. As those contracts come up for renewal and we go out for solicitations, we will find out how much renewable power is out there to supplant the current contracts that we have. So, we do have the benefit of some time.

If we are going to set public policy objectives, stretch goals, we need to be very careful about how those stretch goals are codified. Are these going to be incentive based? Will there be penalties attached for failure to meet some of these goals. We always talk about the carrot and the stick. For a long time the

regulators claimed that they like to regulate with a carrot, not with a stick, and to make sure the carrot just isn't an orange colored stick. So, I think we need to remember those lessons from other experiments we've had.

Other things. We'll address some of these issues both here today and some of the workshops you have already scheduled.

What about the infrastructure needed for bringing renewables to market, transmission in particular. Importantly, we have to consider the rate impact. We will get into some of these topics later on when we talk about the investor utilities and the municipal utilities. I have some remarks to make there, but we are very sensitive to the cost of renewable power and to the rate impact as people have said.

If renewable power is coming in very cheaply, then certainly we should be looking at acquiring as much of that renewable resource as is available, but we want to make sure that we don't burden our ratepayers with tremendous costs and put our company, an investor utility at a disadvantage compared to others.

Of course, if renewable power is coming

in above market, then we need to make sure that there are systems in place to assure adequate cost recovery for the utilities.

There are some financial issues as well that we need to pay particular attention to from the investor utilities standpoint. My colleague, Joe Henri, is going to address at least one of those important issues, debt equivalents.

MR. HENRI: Thank you, Les. My name is Joe Henri, and I was actually the person at PG & E who issued PG & E's last renewable solicitation. So, I do have some first-hand experience there.

I no longer work in the power contracts group, and there's no correlation between those two things, I assure you, but I now work on energy policy issues for PG & E.

Debt equivalence is one of those threshold issues that directly affects California's ability to implement its renewable portfolio standard, and there may be differing levels of understanding about what debt equivalence is. If you will permit me, I'll just spend a minute on it.

The simple explanation is that credit rating agencies assess investor owned utility

balance sheets to assess our risk and then give us a credit rating. Power contracts, such as renewable power contracts we will enter into and other power contracts that we contemplate over the next years ahead of us, are counted by the rating agencies as debt equivalents.

In other words, they look at a long term commitment, they look at a stream of payments that have to be made over that period of time, and they say well, it sure looks like debt. They put in their calculations of our credit risk, they will attribute a certain amount of debt associated with those power contracts into their calculations.

To the extent that there is no offsetting equity or other measures taken to counteract that debt equivalence, that degrades the utility's credit ratings. The consequences of that, of course, are that as our credit ratings go down, our cost of borrowing increases. That increases our costs and costs for our rate payers, which is clearly something we don't want to have happen.

There is a solution to that in that the issue of debt equivalence is being addressed at the Public Utilities Commission, and in particular

in the Cost of Capital Proceedings, which I believe both Edison and PG & E are filing next week in our current Cost of Capital Proceedings.

There are long term solutions that the CPUC can pursue on this issue as well as some very immediate steps that they can take such as establishing a support of policy and some fairly simple procedures to make sure that debt equivalence is recognized as we enter into these renewable contracts and other power contracts to assure that we are able to achieve the State's goals.

Debt equivalence is an important issue. It is sometimes not very well understood, but if you think about it as the part of the financial infrastructure that needs to be in place along with the wires, along with the gas, in order to achieve our goals for energy in California, then I think you will put the right amount of significance on the issue.

PRESIDING MEMBER GEESMAN: Joe, let me ask you on that, the Standard and Poors is published criteria for determining debt equivalence. Have you got as much specificity from either Moody's or Fitch?

MR. HENRI: You're correct, Standard and Poors has issued a description of how they go through that analysis. Others at PG & E and at the Commission and other utilities of course have spent a lot of time with Moody's and Fitch talking about how they perform that analysis.

I guess the nicest thing to call it is proprietary in that it is not a transparent analysis they do. There are a lot of qualitative factors that they take into account as well as some quantitative. The quantitative pieces are pretty straight forward. It is a fairly easy thing to take a look at, an on-going stream of payments and discount it back to a net present value and then some percentage of that is considered to be debt equivalent and add it into your ratios.

There's not a formal methodology that they use for that though.

PRESIDING MEMBER GEESMAN: Looking back over your experience as a regulated company, I suspect you've not always been successful in earning your authorized return or recapturing your expended cost on construction projects. Do you have a better record of recovery of contract

costs, for example "QF" costs from the CPUC than you have experienced historically on your construction projects.

MR. HENRI: I'm not sure I can speak definitively to all the different asset investments we've made in our recovery history there. You are right that there has been some variation over the years. Although with our QF recovery, QF being the only real group of long term contracts that we had entered into prior to energy deregulation in California.

Of course, immediately after AB 1890, we were only doing short-term contracting, so the QF's are the appropriate comparison group. We have been successful in recovering all of those QF costs going forward, a point we've made to Standard and Poors and Moody's repeatedly, but they also look at other factors. As I said it is a qualitative as well as quantitative analysis.

They look at track record, they look at other sort of regulatory stability issues that despite our ability to pay those QF contracts and recover those costs, they tend now to put more risk rather than less on our long term power purchase arrangements.

PRESIDING MEMBER GEESMAN: Yeah, I've spent quite a number of years in dealing with the rating agencies, not with respect to regulated utilities, but in other debt ratings.

I would suggest to you that the focus on contracts that Standard Poors has brought into the public forum, may reflect the fact that you just haven't been doing much construction recently as well.

I think from a historical standpoint, the record is I think pretty clear that your cost recovery risk seems much much much greater historically, particularly in California on your construction projects than it ever has on your contractual obligations.

One eats away at the balance sheet with a depressing amount of predictability in this state. The other, at least to my knowledge, has been pretty consistently passed through and has not had a deleterious affect on your balance sheet.

MR. GULIASI: Let me just try to add a little bit to this. I think you are correct that the risk that we face today is much less than the risk we faced in the past when we were engaged in

very large construction projects.

The regulatory history on cost recovery in our QF purchases and other power contract purchases has improved. We haven't faced the significant disallowances in recent years that we have faced in the past, and of course, one reason for that improved track record has been that a lot of our contracts are now coming through DWR.

We still face some risk with respect to how we administer the contracts, but that risk has significantly been diminished. It is not really so much on the cost of power per say in a post hoc reasonableness review, the risk is minimal, and it is placed mostly on how we administer those contracts.

MR. SKOURONSKI: I'd like to real quick pass my business card to PG & E. We plan to build a billion dollars worth of power plants, and we are looking for equity. If they want to improve their equity to debt ratio, 400 million equity, give me a call. We will carry the debt.

PRESIDING MEMBER GEESMAN: Let's hear from your neighbor from the South.

MR. WOODRUFF: Good morning, Jim Woodruff for Edison, and I have to say we agree

with a number of the comments that we've heard from both utilities and others. We are gratified to hear a number of folks mention how well Edison has done in the past and the extent to which it has embraced renewable procurement today.

We've had one very successful interim solicitation, and we are in the midst of another now.

Having said that, we are very early in this current legislative and regulatory construct and environment. There are a lot of parts that have not been defined. We don't know how they move together. There is a lot of very able effort going on around defining terms in the legislation and how they are going to be implemented.

Dan Adler, John Gelway are here and Tim Tutt, collaborative staff, have done a tremendous job in pulling this together, but it is a complex piece of legislation. It is a subtle piece of legislation that requires definition.

Some of that definition is going to be around accounting. The CPUC has just opened an OIR on the RPS where it is going to be addressing some of the accounting issues. How those issues are addressed will make a vast difference for all

three utilities as to whether they are at 20 percent, how they meet one percent a year, the IPT as it is being called now or the APT.

There are two moving parts here, what is your base line, and what is your load. So, those things can fluctuate from year to year. We look at the legislation and probably SDG & E more than us and perhaps PG & E looks at this legislation, particularly with accelerated goals to 2010 as being some what of a stretch.

Some have said well Edison is almost at 20 percent. Well, these are accounting issues. There are other issues, least cost/best fit, MPR. All of that remains to be defined. Even if you get the 20 percent, say we get there tomorrow, we need to stay at 20 percent under this legislation.

I am sure many in this room are aware that many of the QF contracts that Commissioner Geesman referred to earlier are going off, 2005, 2006, 2007. So, there is an attrition, a potential attrition, to the base line over this period from 2004 to 2010 that needs to be accounted for.

This legislation requires you to stay at 20 percent, so that may very well be a challenge

even for utilities that get the 20 percent. So, I guess our view generally is that the legislature has put in place a mechanism that is both an overall goal of 20 percent, but it also gives you annual progress reports and progress goals. This is the APT one percent a year.

There is some very significant penalties around the APT that the Public Utilities Commission has put into place. So, there is a place to look at progress reports. How are we doing in 2005? How are we doing in 2006, 2007? Frankly, I find it a little bit curious at a policy level we are considering now without having done one single RPS solicitation. It is going to be a stretch to get that done this year.

We've set goals, and we are going to try to get that out. That we are looking at 33 percent, we don't know whether we have the resources, the funding, whether it is PGC funding or rate payer appetite on the utilities side, or ability to bear this burden to get to 20 percent and stay there.

I guess Edison's view today is let's get the parts out there, see how they are defined, see how they work together, do this for a couple of

years, and let's come back and consider this.

PRESIDING MEMBER GEESMAN: You know, Jim, a lot of that complexity in the statute comes from your draftsman, so, there is not a whole lot of empathy among policy makers as to how obtuse some of the provisions in the statute are. I certainly herald the success that you have achieved thus far. I think you started at about 15 percent, but it still is a notable accomplishment as to where you've gotten.

The fact that you've gotten there so quickly without any real clear evidence of breaking a sweat would suggest to me that at least as it relates to your company, we can do quite a bit better.

I reflect the renewable resource development report that this Commission published last fall indicate that 75 to 80 percent of the State's commercially developable renewable resources were within your geographic area.

I think of what president elect Kennedy said. He is a bit of a touchstone in terms of the governance values of this new administration, but on the way to his inaugural, he addressed the Massachusetts legislature and quoted from the

Gospel of Luke, Chapter 3, verse 18 and said, "To those to whom much has been given, much is expected." I think that pretty well characterizes your company's situation as it relates to renewable resources.

I do think that your management should reflect upon the fact that expectations of your company are likely to be quite a bit higher than expectations of others and for legitimate good reason. End of sermon.

MR. WOODRUFF: I can only respond to that by saying I think the wealth of resources that you referred to in the Edison service territory is something that is reflected in the extent to which Edison has procured under prior programs, and that may well be the evidence of what you speak, that in fact, we do have access to those resources.

One of the considerations that this Commission and the CPC will need to take into account in developing longer term policy is simply cost. A number of folks have referred to cost.

That obviously is directly related to supply, to transmission build out, to cost of extraction. I heard the gentleman from is it --

MR. PROBYN: Clean Power.

MR. WOODRUFF: -- Clean Power indicate that there is a synergy between technological advances and sort of PGC funding we are seeing in stretchicals, and I am sure that is true, but the fact of the matter is that is as we go up the tree and we've picked the low hanging fruit, that there are going to be cost issues that have to be addressed by policy makers. A number of folks have alluded to that today.

Simply stated, does the State of California want to subsidize those greater costs associated with that? I don't know the answers to those questions, those are policy level decisions that need to be made going from 20 percent to 33 percent is going to implicate those issues.

Are we going to exhaust PGC funding? What kind of MPR's are we going to see? There are issues that Manny referred to on the supply side that will also need to be analyzed. We aren't really prepared to address those issues, but I would suggest with a rough kind of graph along the lines of what Greg pointed out that you will see a cost of extraction and a cost of availability that increases over time.

MR. ALVAREZ: One other item, Commissioner. You heard today from the other participants that the issue of cost is very important. I think that is something you need to factor in very seriously.

You asked me a question earlier about the emphasis that took place in the 70's and the early 80's. I don't want to retrace that history, but I think you are pretty familiar with it. If renewables are the most cost effective and the most competitive, I think someone said a penny per kilowatt hour, they will come to market and we will see them.

I think that is a component that you all would need to keep in mind. At times in this process, the government policy makers and regulators are the only force in play that actually drive cost down. So, it is your hands that is on pushing that direction, and I think it is very important.

That's all. Thank you.

MR. TUTT: It seems like maybe a time to segue into some of the re-calibration issues. We've talked about potential and how Edison blessed, and it might be a good time to go back

around the table and talk about whether there should be differential targets or standards or obligations for different entities in the room.

I am reminded, though, in terms of costs of renewables and renewables coming in at most cost effective/least cost resources potentially, and I am as optimistic as the next guy. Someone once asked my boss, Marwan Masri, what the policy is when renewables are at cost competitive or cheaper than conventional resources. He replied that is not a policy that is a no brainer.

The policy that we are talking about is to talk about getting the benefits of some of those renewables when they are more expensive in some ways than conventional power. Steve.

MR. KELLY: Before we move on, I just want to respond to that because I too raised the cost issue, but I think we need to separate the wheat from the chafe on some of these obstacles for building out renewables to whatever stretch goal that we are talking about.

I've heard debt equivalency, rate recovery, transmission costs, blah, blah, blah. A lot of those things and not all of those are in the control of the utilities to solve. A stretch

goal or a mandate that would incent them to resolve some of those things would be very helpful. As far as I know, rate recovery is guaranteed under 8057 for any contract they have entered into in a competitive procurement mechanism. That should not be an issue.

The debt equivalence is something that we are dealing with at the PUC or the utilities are and hopefully within a year or so, that should be resolved.

The issue about transmission is very much in control of the utilities. Right now there is litigation going on about who is supposed to pay for that. The utilities, the power authority sit on a lot of capital that they can invest on transmission that's needed in California, and there is a mechanism for rate recovery for that.

I find it ironic that over the last couple of years we've thrown the renewables into this morass of obstacles on transmission, least cost/best fit when none of the other technologies seem to have to confront that as a policy matter up front.

So, most of these issues I think are solvable. Usually the control of that solution is

in the hand of the utilities, and I think it needs to be directed by policy makers and regulators to be get that done in a timely manner.

MR. KLOBERDANZ: I just want to be clear. Earlier when I mentioned transmission as something we need to consider as we determine whether and how soon to add to the goal, that I was not referring to my company's willingness to pay for transmission. I was referring to the ability to get permission to build it.

Thank you.

PRESIDING MEMBER GEESMAN: Okay.

MR. TUTT: Go ahead, Bud.

MR. BEEBE: Bud Beebe with SMUD. Before we get into the part about where we beat up each other about who is going to pay for this stuff, I did want to reflect a little bit on why the present goal is pretty readily accepted by society.

This 20 percent, nobody is fighting it too hard. We have three state agencies that fairly quickly and easily came to the fact that we could maybe accelerate it from the legislated 2017 to 2010 time period. The governor has even suggested that we could go beyond that.

So, there seems to be a great social consensus on the fact that we can do this, and that is predicated I think first of all, on the fact that the 20 percent sits not as a 20 percent step goal but rather it sits on an existing at that time 12 percent of our energy coming from renewables of like kind that we are going to get in the future. So, we had some experience for society to say that this seems to be a reasonable thing.

Secondly, there is growth in electrical demand, both in California and the west in general. So, this gives room and necessity to add additional generation, so that is another comfort level as to why the present goal seems not wholly out of hand.

On the negative side, we have fears of natural gas reliance. We have genuine air quality impacts in our present energy structure. So this makes us all rather comfy with this goal of 20 percent by the legislated time.

If we are going to talk about goal setting beyond the present, we need to find a similar pleasant social plateau, some place where we can all get at least in the same area and stop

quibbling about who is going to pay for it, rather than the question of whether it is at all possible.

I think to do that we really need to clearly articulate both the positive and the negatives of the different scenarios that are likely to ensue. From those things, we can set goals that society can respond to and give us the feed back as to just what they will want.

Included in this are air quality, what are we really trying to achieve with air quality. What's possible to achieve with air quality by adding renewables, or what kind of renewables.

What about greenhouse gas production levels, not just in California, but what is going to happen when the nation decides that is an important goal for them as well?

Transmission growth possibilities. We, at SMUD, plan to do a lot of our renewable energy growth using present transmission and locally if we can. We are going to learn things about the present transmission system that is not adequate to a future that will have certain kinds of dominant renewables within it.

What about the quality of impact across

social and geographic sectors. After all of this, we still have to be able to afford it as well.

Let me say that interim goals are very important in meeting key goals. If we are starting to talk about an accelerated goal as we talked here, the 33 percent or whatever beyond the 20 percent, then what we've done is we've made the 20 percent an interim goal. That is not a bad idea at all.

At SMUD, when we started setting our own RPS, it was back in 2001, and we looked at a ten year time frame. We said over this ten year time frame, some of the contracts that are bringing us renewables today are going to expire and/or change radically.

We thought it was a good idea to set an interim goal, and so we set 10 percent renewables by the year 2006. I think that was a good idea. I know as we approach 2006, and I won't call it panic, but the need to get to hard work to meet that interim goal is an important piece of how we will get to our 20 percent goal by 2011.

Maybe by thinking about a goal beyond the 20 percent, we need to think about the barriers or the comfort level we got with our

present 20 percent and also barriers that might be extent as we reach for more.

The first one I will say is if we are going to go beyond the 20 percent, we need to have some experience, just like we had the 12 percent to start with to get to the 20, we need some experience. We don't have that.

We've heard people talk about we don't have any RFP's or RFI's back yet, we don't know what is going on there yet. We've got to get some of that in hand before we really can comfortably go beyond the 20 percent I think.

Secondly, we need to have some feedback of what is going to happen to the transmission system. This is so key to how all of this is going to fit together. We've got to find out what the hell is going on. Excuse me, what in the world is going to happen with transmission, who is going to control it, who is going to own it, where is it going to go because as you look at that map, that wonderful map the CEC and others have put together as to where these resources are, they are not where the transmission is. That is not good.

We've got to figure out how to do all of that stuff. Also, there are other revealed

choices that will reveal themselves on our way to the 2010 or 2017 goal, wherever you think that is, and that includes some of these things that I've talked about before, air quality, reliance on natural gas.

Natural gas prices going up and down. Remember the last time they went up, they came down again. Remember that? I mean they were never going to come down, and then they did. This was in the early 90's, right? We have to be ready for all of those things, and experience will give us the guts to go ahead with accelerating the 20 percent goal beyond that.

Just two other quick points. The first is that I think it is obvious things sometimes have a way of collapsing, but I think it is pretty obvious that we are going to meet our big energy adders to meet the present goal by adding biomass, geothermal, and wind. Those are the current winners. That is a no brainer.

Beyond that, we've got to realize that to fully develop and deploy larger quantities of renewables, we've got to find a way to protect and develop emerging renewable generation and specifically solar PV and solar thermal. Solar

thermal is a stepchild that should not be left out in the cold.

There may be others too sitting out there, tidal and wave come to mind. So, we've got to have a way to develop these along with the rest of the easy things so that when we need more or we want alternatives to the kinds of renewables that we are developing today, that we will have those available for us.

Lastly, I think we need to adequately and appropriately utilize our current capital investments in fossil generation. For instance, we may find that the current stock of (indiscernible) cycle turbines that are sitting out there and/or their bottoming cycles, their bottoming cycles may be excellent platforms upon which to build a much larger and more robust biomass industry.

We may find that existing infrastructure may lead us to realizing that there is transmission at the end of those things that if we pull that fossil piece out and put something else there, that we may remediate some of the difficulties we would otherwise have with building new transmission. Let's not turn our back on the

existing capital infrastructure that we have.

Thank you very much.

MR. PROBYN: Steve Probyn, Clean Power. Just a couple of points in rejoinder. No. 1 is I think there's something outside of the room that policy makers want to consider in terms of their goals, and that is the production tax credit, which is currently going through Congress as part of the job act.

If that is passed, and of course we have no idea whether it will be, and I don't think anybody does, but that significantly enhances the economics of the renewables that are covered, which now include a wide range wind which has a particular fairly aggressive incentive, other renewables, less aggressive, such as open/close loop bimass, geothermal, irrigation, small hydros.

Those have a very strong impact on the economics of power delivered to the utility. In '01, our firm was significantly involved in a number of Texas wind projects. A number of conclusions fell out of that experience.

No. 1, the cost to the utilities of the wind generation from West Texas, which is a very high quality wind area, was significantly below

ERCOT spot, in the range of half.

Now, of course, you have a different -- we are talking long term contracts versus spot, so there is an apples and oranges element, but the actual cash cost for that power was significantly below what the utilities were paying for spot power, which was about 50 dollars. That was No. 1.

No. 2 was that a number of the utilities recognized that, particularly I guess Reliant TXU contracted very significant amounts of wind power because they realized that in effect, given Texas gas generation matrix, they were able to use their gas generation as in fill, and kind of mid to high range peaking to supplement the wind which had a must run characteristic.

They enthusiastically responded, bought an awful lot of it, and in fact, in '01 I believe the number of megawatts that were built in Texas was 900, which given Texas' relatively smaller market to California, in this state would be an enormous amount of power.

I think one of the things that we want to look at is the external tax and fiscal environment because it could affect our goals, and

I think we should also look in terms of the procurement strategy. Clearly it makes sense if this is past, we are looking at a PTC that will expire in '07, or at least the provisions will. So, that may shape your deliberations in terms of California's policy goals.

PRESIDING MEMBER GEESMAN: Now, in the Texas utility example, both TXU and Reliant were affirming that wind with gas fire generation that they themselves owned, were they not?

MR. PROBYN: That's right or contracted. There is substantial excess generated capacity in Texas, of course, so I am not sure whether they contracted forward. They simply rely on the market to supply it in terms of their intermittent load requirements.

PRESIDING MEMBER GEESMAN: I think that is an interesting question, though, that we probably ought to pursue at some future point in time because California's utilities or the investor-owned utilities don't really own very much gas fired capacity on their own. I think there may be a reluctance to rely on contracted for power to use as an affirming resource for wind.

I'm not suggesting that it couldn't be done contractually, but I think it may be a bit easier if the utility is dispatching gas plants that it itself owns.

Mr. Kelly, I'm sure I've drawn a rise out of you.

MR. KELLY: You've got me going there. Well, I am thinking in California, though, if you have an affective resource adequacy requirement, then the spot energy price is going to be low, kind of a dump market.

The ISO, for example, in California could dispatch around the intermittency of the wind stuff because it has enough resources made available to it. So, I don't think it is a technical or engineering kind of problem, it is just a pricing market designed, which we are moving to that kind of structure to allow that to happen.

MR. PROBYN: The generating capacity may already exist.

MR. KELLY: Yeah, or will soon.

MR. GULIASI: Just very briefly of this whole notion of re-calibration. What I am hearing somewhat consistently from many of the panelists

is that we need more experience. Again, let me repeat, I think it is important for policy makers to set goals, even stretch goals, tough stretch goals.

Then it is the question of putting the structure in place to insure that we can gain experience as we move forward and re-calibrate.

I think this program ought to be addressed on a state-wide basis, and then you have to figure out how to re-calibrate on a particular IOU basis, or if the program is truly state-wide, and it applies to municipal utilities as well as IOU's, then we have to build in a re-calibration process for all the players.

When I raise these issues about the obstacles -- well, let me first say this. I think Tim, you did an excellent job of identifying the benefits. There is no question that there are numerous benefits derived from more reliance on renewable energy. The air quality benefits, the diversity benefits, less reliance on fossil fuels, foreign oil, all of those things. There is no question about that.

We haven't really talked very much except from hearing from SMUD about all those

benefits. So, by design almost, we have been focusing on some of the barriers. By focusing on the barriers, I don't want to suggest that the achievement of a stretch goal is impossible, but it is important to take into account practical reality, and that is detention. It is the balance between trying to achieve a stretch goal as a laudable public policy objective while you address the specific practical realities that we are faced with today.

We have not just been sitting idly by kind of waiting for time to pass to see what happens. As I said, we are going to go out for solicitation, renewable power solicitation in July this summer, and assuming that the PUC puts certain structures in place, we will be moving forward in early 2005 with a request for proposals for new power generation.

We are moving. So, as a state, we are moving forward. Meanwhile, we are out there talking to developers, and we are interested in finding out what might be available in PG & E territory as well as state-wide and what the impact would be to say our transmission system for interconnections.

We have some of that information, and that information is very useful. It is going to be very useful when we move forward with out solicitation. So, we are not just sitting by idly. We are committed to working diligently toward the achievement of whatever goal the state sets, but we want to make sure whatever that goal is, whether it is codified or whether it is enunciated just in a policy statement by this Commission or by all the commissions, we have the structure in place to move forward on a rapid, but thoughtful way to make sure we can achieve that goal.

PRESIDING MEMBER GEESMAN: I think that you are committed. I don't really have any doubt about that. I do want to emphasize that we may all be required to think a little faster than in more comfortable times would be considered ideal.

Last year when the Public Utilities Commission became convinced that it was important to move quickly in order to capture the opportunity presented by the Mountain View Project, it moved quickly. It was able to make a determination that circumstances justified moving quickly. I am hopeful that they are able to do

the same with respect to the Otai Mesa and Palomar Projects in the San Diego service territory. I would expect they will do the same when your procurement process gets under way.

I would point to the directive that the governor sent President Peevey here a couple of days ago, and he emphasized that the loading order established in the Energy Action Plan was of vital importance to his administration. As we make progress with procurement overall, I think it is important to recognize that loading order is going to stay as the anchor of all procurement, and it applies to demand response and efficiency programs and renewables as preferred choices before we get to fossil fired resources.

We had an interruptable load circumstance yesterday in Southern California. That is not supposed to happen in May, and it reflects I think an inability to accurately predict on the part of the lot of the governmental institutions and utility institutions involved in this. We need to aggressively deal with these problems. I recognize it. It is going to push people to a certain level of intellectual or analytic discomfort, but I think it is important,

as the governor's letter has made clear, that we get moving.

MR. GULIASI: I couldn't agree with you more, but in terms of the loading order in particular, and you will see in the filings we are making with the Public Utilities Commission with respect to the procurement proceeding, that we followed the loading order, and we are accurately pursuing cost effective energy efficiency, for example, in all the other programs in the order enunciated by the Energy Action Plan.

MR. TUTT: Joe.

MR. KLOBERDANZ: Just a couple of quick comments from SDG & E on re-calibration, but first I wanted to thank Commissioner Geesman for his what I believe was his support of the contracts and purchases and ownership options we have in front of the PUC right now for approval.

PRESIDING MEMBER GEESMAN: It was.

MR. KLOBERDANZ: Thank you. I wanted to point out that SDG & E is equally anxious to have approval for the demand side and renewable contracts that are part of that package.

With respect to re-calibration, SDG & E's experience so far, and it is limited, is that

there don't seem to be a lot of developers in the system within SDG & E's system, if you will, who are looking to develop renewables, but we are very anxious to find out to test that theory. We hope we are wrong. We do want to get a couple of RFP's out there and see because we have reason to think, for example, that there is a wind resource area that may be developable in our service area.

Other things may be adjacent and transmission may allow us to get things to us rather easily. We really need to see the experience of a couple of RFP's to even consider whether re-calibration is anything we are even in need of.

I can't emphasize that enough. I know I've said it. I can't emphasize it enough. We need to get a couple of RFP's out there, and we may find that we have enough near by. We are hopeful.

There is just a final thought. There is a re-calibration of sorts that may occur all on its own without any commission doing it. That would occur or could occur as we see things implemented that are either under way or being considered in the legislature.

Community choice aggregation, the Core/Non Core legislation, those things could in effect re-calibrate what a utility needs to provide by moving the supply picture for substantial amounts of load to other players. Something that ought to be considered in the re-calibration context. I don't claim to have an answer, but it ought to go on the list.

Thank you.

MR. TUTT: In terms of re-calibration, one question involves mandates versus incentives. I guess another way to put that is maybe we have the same general or structure that is in place now, but the re-calibration is in terms of providing some additional incentives to go beyond the structure, the mandate if you will in those areas where there is resource potential clearly available. What would those incentives be, and I'll start with Edison.

MR. WOODRUFF: Could you repeat the question?

MR. TUTT: We were just talking about re-calibration in terms of using incentives to go beyond the standard mandate that we have in place now in areas where there is resource potential

identified. What would those incentives be, how would we potentially structure that if we were going to go that way.

Maybe one way to preface that is to say PG & E talked about a fair allocation of SEP funds under the current structure. Would SEP payments be appropriate for significant generation beyond the target for an entity if another entity hasn't yet reached their target and potentially might need those funds just to get to the target. That is one way to think about the issue.

MR. WOODRUFF: I guess what you are suggesting is that -- I haven't given this a great deal of thought, but under the current legislative mandates, if a utility were to procure beyond the goals or targets, the question is, would SEP funding be available?

MR. TUTT: As a hypothetical, that's correct. I mean I know that in -- I am not absolutely sure what the current policies are, some of them haven't been put in place yet. Given that there are some entities that would need a lot of development just to reach their target might need SEP payments for that. Should we consider or think about providing SEP payments for somebody

doing generation beyond their target? I know there's flexible -- eventually you might have to procure just to maintain your target, and others will too, so it is not a clean cut going beyond the target.

I am interested in the question of incentives to go beyond the target as opposed to a re-calibration of the mandate as a hypothetical.

MR. WOODRUFF: I'm not quite sure how to address that. It does seem to me that from any utilities prospective under the current legislative structure that whether it is mandated to procure or voluntarily procuring beyond whatever the specified goals are, that it would be looking to SEP funding for any above market, funding associated with those contract, whether it is above 20 percent or below.

I don't see that as necessarily providing an incentive given all of the other considerations that we have discussed today to a utility to procure beyond 20 percent or to procure beyond an annual target given the regulatory risk and uncertainties and cost issues that have been identified here.

I would look at it as a minimum. That

is to say it is unlikely a utility will procure at above market cost beyond its legislative or regulatory obligations without SEP funding, so it is kind of a minimum case.

MR. SKOURONSKI: I think we have to ascertain the amount of SEP funding available and do that again on a balanced accounting methodology. In other words, find the point of financial neutrality. If you a utility goes out and has 2,000 megawatts that they are going to buy, 1,000 is below market, another 1,000 is above market, then basically everything else being equal, that is zero. How much do you have left in the SEP funds? If there is money available in the SEP funds, then I think the utility should be encouraged to go beyond the 20 percent because there is money there, and they are indifferent to it.

MR. ALVAREZ: Right. Tim, I also think your question, the mandate and the RPS is not just the percentage number. There is also a price component in there. If renewable projects come in at market price, I think it is ultimately an accomplishment that you didn't need to use the supplemental energy payments and in effect you can

return it to the rate payer, that's a benefit.

That is something to think about there. You have to consider what that price is. Today we heard some optimistic estimates of what people thought they would produce at.

MR. SKOURONSKI: Yeah, but I'm just talking about the actual solicitation. I'm not talking about our estimates, but what every utility gets, then find the point of financial neutrality.

MR. TUTT: Greg.

MR. MORRIS: Just an observation on the need for re-calibration. I think that issue is very much tied to the issue of whether or not REC trading will be allowed. That is just an observation I wanted to make.

MR. TUTT: I agree. There is a connection there. We will talk about that further in the afternoon I'm sure.

COMMISSIONER BOYD: It's a big connection, and I think that is a very major issue when you start talking about funding and marketabilities.

MR. KLOBERDANZ: You know I touched on it earlier, but you asked about incentives. The

folks around the table seem to be talking about primarily about incentives to be paid that in effect, benefit the renewable generators. I kind of assumed you were talking incentivising utility shareholders to go out and do more than they have to do.

MR. TUTT: I didn't mean to take that off the table, and I am more than happy to talk about that. One incentive is just giving kudos for going beyond and getting good press for it.

MR. KLOBERDANZ: That's good, and the shareholders read about that in the annual report, and that is good. They also respond to earnings to some extent. SDG & E kind of takes some pride in the belief that probably not unique among California utilities, but certainly up there with the rest of them, we have the ability to come up with incentive mechanisms, shareholder incentive mechanisms to do things that policy makers want done. While I didn't bring one with me today, I am happy to work on that.

MR. ALVAREZ: Do you want to go, Steve?

MR. KELLY: Sure. I support the concept of utility incentives. I would not be supportive of using public good charge money to support

utility shareholders for doing what's public good.

MR. TUTT: Agreed.

MR. ALVAREZ: I want to come back to a point that Steve Kelly made earlier about what's going on with the renewables because I think it does get into this incentive activity. You heard the phrase earlier, I think Les brought it up, about the carrying the stick and the regulatory frame work.

I guess from my perspective I'd be very pleased if I had a sustainable regulatory framework in which we are working in. I think that's an important part of the Energy Action Plan and the procurement process that the joint letter of Commissioner Geesman and President Peevey issued leads in that direction.

Steve brought up a point about the issues that are being raised to the renewable area. At least I got the impression that he thought it was some what unfair in terms of dealing with some of the transmission issues, some of the costing issues and the environmental issues.

I guess I didn't want to leave the Commission with that perception. I want to bring

a little bit of a point to that.

I think all power generation goes through that. When you sit through the Energy Commission's permitting process on a thermal facility, those issues are discussed before you, and the transmission constraints and the implications of the system, the environmental concerns, they are all addressed.

I think we have just chosen as a matter of policy that we are going to deal with renewables under the RPS rubric and that is going to be done jointly with the CPUC and the PUC, so a lot of the issues that I heard Steve Kelly raise are issues that are addressed to all facilities, not just renewables. I didn't want to leave you with the impression that somehow renewables are getting more burdened in terms of the issues they have to address.

MR. TUTT: Okay. Any other comments or questions on this first area?

PRESIDING MEMBER GEESMAN: Lunch break.

MR. TUTT: It is time for a lunch break. Okay. Can we all get back by 2:00 for the second round table, and we will move to the third after that.

(Whereupon, the workshop was adjourned, to reconvene at 2:00 p.m. this same day.)

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AFTERNOON SESSION

2:00 p.m.

PRESIDING MEMBER GEESMAN: Let's get started then. Commissioner Boyd will be joining us shortly.

MR. TUTT: For this round table is addressing the public utility participation in the RPS, the RPS as it applies to publicly-owned electric utilities. We talked a little bit about the basic underlying law in the earlier presentation, and everybody understands or is probably aware that there have been various proposals to change that law in the legislature this year.

We are just interested in finding out what progress publicly-owned utilities have made and answers to the other questions we've proposed in the work shop notice. I know, Jordan, you filed some comments in our docket on this issue, and we appreciate those, and we will be taking those into account as we move forward.

Shall we start around the table again? Bud, do you have --

MR. BEEBE: Make me start, huh? Okay, I can do that.

MR. TUTT: I can go the other way.

MR. BEEBE: No, no. It's not so bad really.

Before addressing the points in the announcement more directly, I'd like to just to take a couple of seconds to both organize my thoughts and to just say that publicly-owned utilities which still sell into the California market about 23 percent of all of the electricity used by the State have been around for a while, and I think we have been pretty reliable partners in affecting public policy at many different levels.

It is a responsibility we take seriously. It is important to note that there's sometime unsettling or not very comfortable tension that occurs between the publicly-owned utilities and the privately owned utilities or investor owned utilities.

That is because if we had just one system, if we were all one type or the other, I think things would play out maybe further into the bad zones than they do with the tension there. What I mean by that as we go through each of these waves of things that have to be dealt with and how

we deal with them, unless you have a little competition, it is hard to see the point at which you need to break away and change things a little bit.

Most of the legislation naturally because this is a very important state-wide goal, this 20 percent of renewables over the next ten years, most of the attention has been paid to the privately owned utilities. I think if you look to the work that is being done by the publicly-owned utilities and because of our close ties to the communities, you will see the ways in which you might want to optimize what's been already done more formally by the legislature to the privately owned utilities.

For instance, and I mentioned this in our previous session, SMUD found it very helpful to put an interim step in. The ten percent, a 20 percent, when we adopted our goal.

Also, while this forum is squarely focused renewable energy, that's appropriate, but there are a lot of attributes that go with renewable energy that we just sort of assume when we say renewable energy. One of them, and I would like to highlight this is the greenhouse gas

emissions problem that we have in the United States and we have in the world.

This is my lead in to my more formal stuff. When SMUD adopted a 20 percent renewable energy content back in 2001, that predated the state-wide legislation by almost a year. It was done because there was need to show leadership in what we thought was both an achievable goal and an important goal for California. It also showed leadership in green house gas reduction. I just think that is a real important piece to put in there.

Yes, we do have two goals currently. One is to have 10 percent non-hydro renewables by 2006, and 20 percent non-hydro renewables by 2011. We feel those are achievable. We are aggressively going after both of those goals, and I guess watch us as we progress down the track.

You will notice that I said non-hydro renewables. As we all know in this room, there is a different set that is legislated, and that is the eligible renewables. That is different than non-hydro renewables.

This points out that SMUD, I guess because we can, had relooked at what the eligible

list of renewables is. We feel that we can show some leadership by looking at that list and seeing if we can improve on it a little bit.

So, this gets to question two which is the implementation rules. Generally, the resources that are eligible for state-wide requirements are eligible for ours with the exception of that hydro piece. We think that there's one or two other places where we should differ from state-wide. Not that we aren't looking at state-wide requirements and constantly trying to adjust to them, but there are some changes.

The first one, let me say, is out of state resources. We may well have some opportunities to partner, particularly with other publicly-owned utilities in an out of state situation. Bringing back that power to California and bringing the renewable energy content with it, whether they call them racks or whatever, we think it is a very important piece, and we plan to include that as an option in meeting our RPS.

Secondly, we think there's good options for renewable energy in consort with some fossil-fired facilities. A good example of that would be

our co-generation project at the County Waste Water Facility. There, the County Waste Water Facility produces digester gas that makes up fuel for some 14 percent of all of the electricity that is made by that facility.

We think it would be not a good idea for California to turn its back on the option of using in this case digester gas, maybe in a different case bio-mass, maybe in a different case some other situation where you could use renewables profitably and easily with fossil-fired products.

As you know, there is currently a requirement in the state that if your fossil-fired piece of your generation is more than 25 percent, then nothing can be called renewable.

On the other hand, if there is less than, but let's say a sizeable amount like 20 percent that is fossil, all of it is still counted as fossil. That is a dumb rule. Sorry, Tim, were you a proponent of that?

MR. TUTT: Just to address that point. It may or may not have been a dumb rule, but we have changed it. It is more along the lines of what you suggest now. I don't mean to cut off your presentation, but I just wanted to let you

know that.

MR. BEEBE: No, if you have changed it, let me know. I appreciate that. Thank you very much.

We plan to conform our non-hydro renewable rule more closely with what state-wide rules are. In fact, the day after tomorrow, we will take to the Board the question of whether we should consider small hydro in our renewable portfolio standards. So, we will see what they say at that time. We have recommended that they include it.

MR. TUTT: Right now, it is a non-hydro standard, and you might now change to adopt a more closer to the eligible renewable standard that we have.

MR. BEEBE: That would be correct, yes. Planning is good, coordination of plans is good, and we plan to coordinate with the State as we all approach the building of new renewables in the State, so we plan to participate in this forum and other forums that the State will set up and to share our knowledge and our plans as we go forward. We certainly underscore the need to have coordination of state-wide goals.

Green pricing programs. SMUD has a Greenergy Program, and the Greenergy Program is for those who don't mind paying a little bit extra to get renewable energy content and a piece of that fair market value back to them that their RPS is accounted for separately than SMUD's non-greenergy renewable content. So, we will keep track of the renewable energy content of both our greenergy and our non-greenergy customers, and the RPS will be divvied up separately accordingly.

I think the barriers to publicly-owned utilities accelerating the RPS target are what all of us have talked about before. I tried to in my previous comments really tell you what those are, and I will just let the record stand there.

Let me say beyond that, though, that SMUD is I don't know, I guess we are unique by being pretty ordinary in the sense that we will have growth in our area, so we will have growth in retail sales, and we will need to add resources between now and the next decade.

We have a good solid set of experiences with renewable resources as does the rest of California. We are in a good transmission nexus, so I think we will be able to take advantage of

some of the outlying renewables that will be attached to us through the grid, so all of those things are just like sort of the State of California in its gross or bulk content.

We are a little bit unusual like I say because we are so ordinary in that way. Other publicly-owned utilities may not be in that same condition. They may have an over abundance of resources currently. They may have different growth patterns. They may be very small and constrained financially.

So, when dealing with the publicly-owned utilities, it is important to allow us a little bit of room to do the good work we do and to maintain that competitive tension between ourselves and the investor-owned utilities so that you can see what good quality renewable programs really can look like.

Thank you.

MR. TUTT: One question I have, Bud, is in terms of the interim goal and then in between that and the final target you have. Is it fair to characterize the IOU RPS as having a series of interim goals, annual interim goals? Would that be reasonable to look at for --

MR. BEEBE: You know, the law seems to be clear on that, and yet the process that was set up by the law doesn't seem to be that clear, so I don't know how to answer that honestly.

MR. TUTT: Just to clarify the question about using a certain percentage of fossil fuel. We have gone back in our guide books which we adopted April 21 and suggested that going forward once we get the WREGIS Tracking System, we will be looking to count only the renewable portion of a project.

We are in the process of modifying those rules as we speak and intending to adopt modifications on May 19. There will be slight changes to that general concept, but we have switched from considering any facility that uses more than 25 percent renewable fossil fuel, totally non-renewable in any facility that uses less than 25 percent totally renewable.

COMMISSIONER BOYD: Bud, let me assure you, I for one have never considered you and my local utility as ordinary, although you did say you were unusual, so you are kind of schizophrenic there, but in any event --

MR. BEEBE: Thank you, Commissioner

Boyd, I appreciate that.

MR. SKOURONSKI: Are we open? I fully concur with Bud. I think the mutual benchmarking concept has been very vital in basically cutting the deck, whether you are a utility IOU or utility Muni. When I worked at the Edison company, we always watched the DWP rates. I'm sure if I worked for the DWP, we would be watching the Edison rates.

I do have one caveat, though, with respect to transmission. I'm not sure if this is true, but I was told this morning that we had an outage in Southern California primarily because DWP took out a line, and they are not under the ISO scheduling, and that line became very very much needed during the heat wave yesterday. I think that characterizes or illustrates the concept that there does need to be close coordination of transmission with respect to Muni owned line and an IOU owned line.

PRESIDING MEMBER GEESMAN: Frankly, I have to say looking at the internal memos that I have seen, I have not seen that pointed out as a contributing factor to yesterday's occurrence. I am not saying that it wasn't, but I've not seen it

mentioned in any of the internal state or ISO related memoranda that I have read.

MR. SKOURONSKI: My statement is hearsay, so I can stand corrected.

MR. KELLY: Just real quickly, I don't really have much to comment now, I defer my time, but I am interested in the publicly-owned utilities response to question two which deals with facility eligibility criteria and the discretion related to that, and essentially if they are subject to they feel the definition that is in SB 1078, I guess, and other bills because the question of large hydro comes up here, and I just wasn't sure where we were on that as a policy matter. So, I defer.

MR. TUTT: You did hear SMUD's response to that, that they don't count any hydro right now, and they will be potentially adding small hydro.

MR. JORDAN: You want a real quick response to that? Some do and some don't.

PRESIDING MEMBER GEESMAN: Yeah. We are aware of that and hoping to get greater elimination as we move forward.

MR. TUTT: Les.

MR. GULIASI: Thank you. Les Guliasi, PG & E. I just have one point, but an important point to raise. I made mention of it earlier this morning. We believe that whatever program is put into place should really be applied state wide, and should apply not only to the investor owned utility, but it should apply to the municipally owned utilities, as it does now apply to community choice aggregators and to energy service providers.

The reason we believe that is just really you know just a simple matter. It is a fundamental issue of fairness and equity. You know, as I mentioned this morning, we are very sensitive to the rate impact of the renewables program. To have a standard applied to the investor-owned utilities, but not applied to others, potentially puts greater strain on our rates, the rates of an investor-owned utility, PG & E in this case.

There are areas where the municipal utilities and the investor-owned utilities compete, compete for new development, and just as a matter of kind of fairness and equity and a level playing field, we believe that the program

should apply state wide.

Thank you.

MR. ARTHUR: I'm Dave Arthur from the City of Redding, and I will try to address I guess a couple of those questions.

First, I would like to talk in general terms. That is that the City of Redding supports the efforts of the state to move toward the development of renewable energy. The recent CEC report certainly points out the fact that we need to be diligent in efforts to expand the diversity of resources that we have within the State and possibly as it pointed out, we may have to go outside of the state as well.

As it relates to the City of Redding, we are taking this seriously. I have to point out that we don't have a large service area in terms of geographic square miles. We don't have a lot of wind in Redding, we do have a lot of heat.

When you look at resources that are indigenous to our service area, we are somewhat limited. Within that, we have made a commitment to do some photostable work, particularly on new civic structures as it can be built into the design of those structures. We are currently are

attempting or have plans to include photabletaic on a new fire station.

We have made intensive efforts to look at a solar thermal project that would interface with some of our existing plants at Redding Power. Here is a potential barrier. What we've discovered or we think we have discovered, we are not positive of this, but in case of the solar thermal, there apparently is not a robust competitive market for some of the proprietary technology. It appears that technology is often priced based on what the vendor thinks they can get in the form of mandated government subsidies to raise the price. It doesn't appear to based necessarily on the cost of the technology itself.

As a result, the work we have done to this point suggests that is almost cost prohibitive.

I raise this issue because if we were successful in putting this particular project in place, it is our understanding from the vendor that we would be the most northerly point where this technology has been applied. To this point, it has been applied to more areas close to the equator, and then it would then potentially open

up new possibilities, and we continue to be hopeful that we will succeed in that area.

As it relates to hydro, we take a view that one, the separation of hydro between small and large is interesting. It certainly has a political genesis. We are having a lot of trouble understanding how it has a basis in physics, but we think even there, there is room for a gradation. That is that there needs to be a distinction made between the historic hydro system and improvements to that hydro system. Specifically in the past several years, we have invested western customers in the neighborhood of about $30 million to significantly improve the efficiency of the hydro system.

In that sense, we are getting more electricity from the existing supply of water with absolutely no incremental change in the environmental impact from the river system.

We think that when we go out and make investment to improve the efficiency of the existing system, that certainly should be considered incremental addition to the renewable system whether or not we ever find common ground on the historical hydro system.

We think there probably will be other kinds of opportunities like that where through an incremental investment, we can get greater output from the existing hydro system, not only that we are associated with, but certainly the investor-owned utilities may have similar opportunities. We would not want to discourage that type of investment. I am hopeful that we will get some adjustments in the definitions to at least to acknowledge that type of resource.

The City of Redding has passed a renewable portfolio standard, and we do hope to meet the expectations as the law was previously written, and we will make every effort to comply if it is modified.

Thank you.

PRESIDING MEMBER GEESMAN: Thank you.

MR. JORDAN: Thank you. Jerry Jordan with the California Municipal Utilities Association.

First I want to talk a little bit about this myth that we continually have perpetuate that the investor-owned utilities have a mandate to add renewables while the municipal utilities don't.

SB 1078 created a goal for investor-

owned utilities and created a similar goal for municipal utilities.

The investor-owned utilities are not required to add a single kilowatt hour of renewable resources if it exceeds the amount of money that they are currently spending on the public benefits charge.

That is not much of a mandate. It so happens because of poor resource decisions from one of the regulators in the state, Commissioner, the investor-owned utilities were a third under resourced and ended up purchasing about a third of their power off of the spot market.

Municipal utilities did not divest any of their plants, and are therefore much more fully resourced. So, the ability to be signing short or long term contracts for renewables isn't the same when you actually have quite a bit of power.

Nonetheless, in the State of California, municipal utilities, which represent somewhere up to 30 percent of the load, are investing in more new renewable resources than the investor-owned utilities are. We have some 1,600 megawatt state-wide that are either under contract or that we are building ourselves, and I think that says quite a

bit.

One of the things that is irritating is to hear this level playing field argument. When someone says they want a level playing field, they mean tilt it my way, so I am running downhill and everybody else is running uphill.

If we had a truly level playing field, then we would be forced to take profits out of the system, and they would be forced to allow the public to vote on their resource plans and subject those to referendum as the people in the SMUD service territory did with Rancho Seco.

Maybe we would make that trade. Most of the municipal utilities in this state have adopted a state-wide standard that is similar to the states or greatly exceeds it. Some of them are including large hydro and some are not.

I'll just give you the first utility on our list for instance, the City of Alameda has adopted a program of 40 percent renewables by 2017. They are currently 50 percent eligible renewables under the state definition and 80 percent renewable.

Another one of our utilities, the Trinity County Public Utility District is 100

percent renewable from large hydro. Applying the exact same standard and they will be for the next 15 or 20 years from allotments that they have out at Trinity, applying the same standard to them would cause them to have to sell off or not use some of that large hydro and go out and build a wind plant.

That doesn't seem to make a lot of sense, but it does accentuate the differences in the service territories of the 35 or so publicly-owned distribution systems in the State of California.

The Los Angeles Department of Water and Power has 30 percent reserves. One of the proceedings that you are all involved in is trying to determine how to get all of the load serving entities to have adequate reserves.

Having Los Angeles divest some of those plants in order to acquire the appropriate number of renewables probably doesn't make sense. Nonetheless, Los Angeles is about to adopt a very aggressive renewable program which includes a 25 percent over market price subsidy that they are willing to pay for renewable resources.

I think when you look at all of those

things, some of the Northern California utilities are about to have dramatic changes in their western area power administration contacts which are large hydro, which will greatly affect their resource plans and maybe some of them will speak to that.

MR. TUTT: No comments on that, huh?

MR. KNAPP: I'm Karl Knapp from the City of Palo Alto. I'm going to be a little more brief and just try to answer these five questions that are here.

The City of Palo Alto passed its own long term electric acquisition plan. We call it LEAP, which includes our renewable portfolio guidelines of 10 percent renewable by 2008 and 20 percent by 2015. This was adopted in October of 2001, less than a month after SB 1078 was passed.

We tried to beat it, but the Palo Alto process is a little bit slower than the state process.

We are using the CEC definition of eligible renewables for that definition, and it is in addition to the green power program which is in its first year has gone from no where to being the number two participation rate in the country.

It is in addition to the public goods charge, so we are not intending to spend any public benefits money on this involuntary program.

We also support an active PV program, energy efficiency and RND. In fact we are chairing a CEC Peer Project with the Public Renewables Partnership.

This long term plan, including our own RPS -- it was derived based on customer preferences and not really anticipating that the RPS would ever pass after watching 528 go by and then 1078, we weren't sure if it was going to pass or not. It is all based on what our local customers said they were willing to pay to have a little bit more renewable energy in their mix.

We picked a time line based on how long we thought it would kind of take us to learn how to really manage these in our portfolio. It closely matches, but is a little more accelerated than the original legislation.

That gets to the importance of having local control to be able to be consistent with the incentive that municipals have which is to maximize value to its customers. At least in Palo Alto and I think in most municipals, there is an

awareness of the sustainability associated with ones own consumption, whereas for the IOU's their incentive is to maximize value to shareholders which may or may not be related to the consumption that they are serving.

Getting to the question of what is passed the 20 percent, I haven't heard a lot yet about what are the objectives of getting past 20 percent, what do we want to accomplish with the 20 percent or the 33 percent. Renewables are not the only way to obtain those objections, and we should maybe be taking a step back and saying what do we want to accomplish and by what means can we accomplish it.

Renewables can accomplish some of those, but if I have to go buy some renewables instead of a fuel cell or a morphus middle transformer or new runners for a hydro dam, it may not be the best for the state. That is really all of my comments.

MR. BERLIN: I'm John Berlin from Northern California Power Agency and basically NCPA is a joint powers agency made up of sixteen publicly-owned utilities in Northern and Central California. Both Redding and Palo Alto are members of NCPA. NCPA, in turn, is a member of

CMUA.

Basically what I would just like to make some comments and give you our position. We totally support the goals and objectives of the state-wide energy action plan, both NCPA and SMUD are working with the PUC on the energy efficiency portion of the state-wide energy action plan to see how the publicly-owned utilities can be incorporated into that.

We strongly support green pricing. Utilities like Roseville and Palo Alto have been very strong in areas like that with programs.

When it comes to large hydro, the majority of our members are reporting their renewable portfolios in two ways, both with large hydro and without large hydro so that both the CEC and their end use customers are seeing with or without hydro into that thing.

One of the points I would like to make out is just the diversity of the public. In other words, if you try to standardize state-wide goals and things like that, we probably out of our sixteen members, a third of them have little or no load growth. They are either resource oversubscribed, they are tied into contracts, or

whatever it is.

So, you look at those individual situations and it is one thing to be Roseville or SMUD. It is another thing to be Ukiah, Gridley, or Biggs, so that is the kind of diversity you are getting with publicly-owned utilities.

NCPA for the last year has been through a green power RFP process, and for its members we got bid in probably between 1,200 and 1,300 megawatts this past year, and it is from resources all over the West. Everything from you know the geothermal, the wind to landfill gas, that kind of thing.

One of the things I would just like to caution at, there's a big difference between setting say theoretical goals and actually going out and negotiating contracts. Everybody right now is fairly risk adverse in terms of what's happened with you know the past power contracts with power marketers, things like that.

If you look at what the credit worthiness of who is bidding in, the actual contract negotiation process, you are going to see a fairly high level of risk associated with these renewable processes, and so that is just one of

the things I want to caution you at when you go through the state-wide RFP's look like that.

When you actually go into the contract negotiations, there is going to be a fair amount of risk management required in those types of contracts. So, one of the questions I had was what are the costs that the WREGIS System is likely add to the price of renewables.

We are working with Western Area Power Administration now on somewhat of a complimentary system to the WREGIS System that would be used by publicly-owned utilities to both track and trade green tags or tradeable credits, so we do have a question, what is the WREGIS administrative structure. What is that going to cost to the price of renewables.

Basically, those are my comments today, so, thank you.

PRESIDING MEMBER GEESMAN: Let me try and stir things up a bit by goading my friend Jerry. I actually tend to think that local control is a very very beneficial factor to the state's overall ability to accomplish these goals. I say that because the public policy institute surveyed Californians about a year ago in 2003,

and then prior to that in 2002, and found in both surveys in excess of 80 percent of the respondents felt it desirable for California to double its reliance on renewable sources of electricity over the next decade.

I strongly believe that 80 percent plus is probably found just as frequently in municipal service territory as it is in investor-owned service territories, and ultimately the elected nature of the muni's government structure will provide I think a very substantial degree of responsiveness.

I wonder though, Jerry, why you think this misperception exists. I agree with the way you recount the record in terms of all the muni's.

MR. JORDAN: I'm not sure that the misperception does exist amongst the public. I think it exists across the street primarily because of interest groups that have been lobbying to that effect. We were only recently able to gather the information about what in fact folks are doing, and frankly I was surprised that it is as strong as it is.

I made a presentation to the trilateral, the joint -- whatever that organization's actual

name is, and I challenged the investor-owned utilities to come up to our standards, especially if you look at the Northern Californians. There are some historical differences.

John's members, looking at the NCPA, are overwhelmingly have a large amount of resources, and I would have thought previously that it was substantially in large hydro, but it is not. They have even by the eligible standards, and I agree with Redding, I don't understand why water falls only on small dams and not on large dams.

Be that as it may, it seems to me that one of the things we should be doing is informing the public of what in fact we really do have in the way of actual renewable resources in California.

If you then need to for public policy purposes to set the goal at 40 percent instead of 20 percent, then let's do that, but let's be up front about what it is we are doing so that the public can see whether or not they are willing to pay the extra money for that.

I think you will find in places like Palo Alto and SMUD that in fact the public is willing to pay extra resources. My concern really

is the one size fits all. There are a lot of different circumstances. You know everybody always focuses on LA, but LA has 30 percent reserves and they provide at 880 megawatt to Edison not too long ago because of they didn't have enough in their contract apparently. That was just a few weeks ago.

Having those reserves are valuable, we thought they were valuable in 2001, we have other small utilities that are not going to be procuring a lot of resources. If you were the City of Biggs and you have a population of 2,000, how do you add one percent a year? It is a very difficult thing. They are not all the same, they are not big like Edison and PG & E are, and they can't just meld all of that stuff together.

I don't think there is a utility in this state that wouldn't share that goal and wouldn't like to increase the renewables. They've spent a lot of money, the City of Santa Clara, in the late 70's became the first solar utility in the United States. They spent a lot of money on fuel cells.

SMUD in Palo Alto and others have championed conservation, and frankly, one of the things we are hearing is that if you look at all

of these things together, you may want to spend more money on conservation than some of these renewable resources.

I don't think there is any opposition to the goal or to the stacking order that you developed, but you have to have enough flexibility for utilities that have different circumstances to not be violating the law.

PRESIDING MEMBER GEESMAN: Yeah, I doubt, though, that you get much flack about the Trinity's or the Biggs circumstances, and I don't really find that the large versus small hydro issue to be particularly moving.

I respect the legislature's right to define the requirement however the majority of the legislature see fit to define it and feel that at least this Commission is compelled to follow that law the way it has been written.

I think your problem stems from the fact that widespread perception that what Sam Yorty used to call the City of Los Angeles is out of step. Their abundant reserve situation certainly hasn't inhibited discussion of another coal unit at Inner Mountain, their proximity of transmission lines to the Tehachapi went wind resource,

certainly hasn't done anything to encourage the use of those lines by third party wind generators.

I think indisputably there is a very widespread perception that the City of Los Angeles is not doing its part, and I note that they aren't here today, but perhaps you could speak up on their behalf.

MR. JORDAN: I thought I had. I have provided this for the record, if you look at their proposal is before their city council right now to reach -- well, let me read it here. Their current policy is that they will meet have their load growth through renewables and energy conservation.

They intend to adopt a new policy that will allow them to add 20 percent renewables by the year 2017 providing a subsidy that does not exceed -- not including their public benefits charge by the way, that does not exceed 25 percent more than their alternative costs of power.

I don't think the proposals from any of the investor-owned utilities meet that standard.

PRESIDING MEMBER GEESMAN: I think you'll find in that statement the source of your problems. I don't think that their commitment or hoped to be made commitment does in fact parallel

that which state government is holding the IOU's to.

MR. JORDAN: With all due respect, Commissioner, I don't see that the state government is holding the IOU's to anything when they don't have to spend any additional money to meet that standard. You are asking the City of Los Angeles ratepayers to spend more money.

PRESIDING MEMBER GEESMAN: I have accomplished what I wanted. Are there other comments or questions?

MR. JORDAN: I certainly will relay your comments to them.

PRESIDING MEMBER GEESMAN: I hope you will.

MR. ARTHUR: I'd like to add from Redding's comments, SMUD made a comment that we share, and that is that because renewables often are very site specific, we are hopeful that when we get final resolution of our policies, if it turns out that it is cost effective to develop renewables out of this state as well as within the state, that we will have the flexibility to go where it is cost effective.

While it may not be as much of a benefit

environmentally to the state, it is certainly a benefit to the overall country when we use more renewables and less fossil. So, I just wanted to second what SMUD had said there.

PRESIDING MEMBER GEESMAN: I think the Energy Commission and the PUC and the legislature have made very clear the intent to have out of state renewable resources qualify for the renewable portfolio standard. In fact, I think much of the motivation underlying the development of the WREGIS System is to stimulate that development all across the WECC. I think that will serve as a very constructive downward pressure on renewable prices in California as well as stimulate the development of the industry in California and elsewhere.

Steven.

MR. KELLY: Thank you, Commissioner.

As a renewable advocate, and someone who wants to see more renewables and having been around for a long time and having listened to for example the City of LA talk about their renewable program for so long, as I indicated earlier this morning in the formal workshop, the best thing about the RPS in my view is that it is based on a

count of energy against sales.

The program goals are great, and I think that the fact that the muni's have got all of these goals on paper are good, but really you hit the road on how much of the sales at retail which is measurable.

I am hoping the Energy Commission is in a position to identify that number, so that we can get a really good sense on an annual basis about how we are progressing toward these not only annual requirements, but the full goal.

I've heard Los Angeles talk about a renewable program for years and never saw what I thought was a significant product come out of that.

PRESIDING MEMBER GEESMAN: I subscribe to the view that their program has been all hat and no cattle, but that general manager is not there anymore.

MR. JORDAN: I would suggest that I do think they have about 110 megawatts of winds that they are currently developing by the way.

PRESIDING MEMBER GEESMAN: Falls into the category that Mr. Kelly described, talked about but not yet delivered.

MR. JORDAN: I think a lot of what we've heard today has been talked about and not yet delivered.

PRESIDING MEMBER GEESMAN: I think Edison would care to differ, and I think San Diego would as well. I actually believe despite their insolvency, PG & E has done pretty well over the last couple of years and many of your members. I would say virtually all of your members with a couple of notable exceptions.

MR. KLOBERDANZ: Joe Kloberdanz from San Diego. I was actually pretty encouraged to hear from a number of our colleagues in the municipal utility industry the kinds of plans and progress that is under way.

I would assure Mr. jordan that I think there is at least one investor-owned utility in this state that does understand the definition of level playing field. We understand that is not always easy to define because you've got differently situated entities sometimes.

With that in mind, I would just urge someone, and I think the Energy Commission is probably the appropriate place, to actively monitor, assess, encourage, report on what is

going on in the municipal utility area with respect to renewables.

The legislature and several state agencies and commissions have agreed that a renewable portfolio standard as defined is a good thing for approximately 70 percent of the ratepayers in the state.

It is hard for me to understand how something similar wouldn't be good for the other 30 percent.

We have no desire to do in the good folks of Biggs or Trinity area, but there is -- maybe exceptions need to be made for small entities like that or entities that are unusually situated, but someone needs to look at this overall and keep an eye on it and monitor it. We would just urge that be done.

MR. TUTT: Maybe when SB 1078 was passed and one version of it said that the municipal utilities were going to report that information to the Energy Commission and it ended up being in final form report to their customers that information. In which case, SMUD is the only one that has to report to us. So, I think somebody -- we hear that somebody should be monitoring, and

maybe on some basis we can take that up, but there's no mandate as I am aware in law for that reporting to come to us.

MR. JORDAN: It is public information, you are welcome to it.

PRESIDING MEMBER GEESMAN: Do we have published on our website the submittals that Mr. Jordan provided us?

MR. JORDAN: Yes.

MR. TUTT: I'm sure those can be docketed on our website. Were they submitted electronically?

MR. JORDAN: Yes, they were.

MR. TUTT: I would guess that they are on there or will be on there then.

PRESIDING MEMBER GEESMAN: I found that a very valuable source of information and a very impressive performance as well. I think you are right.

MR. JORDAN: Why do I feel so beaten up today, then?

PRESIDING MEMBER GEESMAN: There is a misperception, but I think it is a misperception based on some pretty sound reasons.

MR. JORDAN: Commissioner, I just want

to respond very briefly to San Diego.

I want to again emphasize there is no mandate on the investor-owned utilities.

MR. ARTHUR: If I could switch just a little bit. Earlier I mentioned that renewables tend to be site specific, and depending on which renewables emerges the most cost effective and probably will turn out to be the variety of them will, they will likely be located in areas where we did not build transmission necessarily.

We have emerging in another part of the state a policy that implicitly at least assumes that you can build a power plant anywhere you want to. It is my hope, and I think it is the City of Redding's hope that the various efforts under way at the differing regulatory authorities can be coordinated in such a way that when we put them together, they lead to a cohesive hole rather than to the null set.

If it turns out it is the null set, we are going to be very unhappy come four or five years from now when we have a very serious problem that requires five years lead time and we didn't do anything with those five years.

I know you are unable to solve all of

those problems, but your agency has done a fine job of trying to bring together all of the pieces in a way that is certainly superior to what the other agencies have done, and so hopefully you can serve as a forum to point out where there may be inconsistencies in policy that could give us difficulties in the future.

PRESIDING MEMBER GEESMAN: Well, I think in particular as it relates to the status of our existing transmission system, that remains a major weakness in California's mix, just not just its physical mix, but its jurisdictional mix of different agencies.

Integrated Energy Policy Report that Commission Boyd sheparded through this Commission makes as what I regard as one of its most prominent and important recommendations that the state finally come to grips with the permitting problems that beseech the expansion of our transmission program. I think that report also goes on at some length to say that we will not come anywhere close to achieving our objections in renewable resource development without substantial investments in upgrading the transmission system.

That report is under consideration now

in the governor's office, and I think he will respond in due course, but you make a good point. We have some major deficiencies in our system as it exists today, and those should be within the capabilities of state government to resolve.

MR. TUTT: I just want to challenge Jerry's statement that there is really no mandate on the IOU's for a second.

I think we all recognize that there's a potential limit on PGC funds, but to the extent that the IOU's have these annual procurement targets that they are required to meet at least initially, I think everyone in the room in the state expects the PGC funds are sufficient to meet those initial mandated interim targets.

Eventually, there may be an issue, and eventually policy makers may have to address that, but at present, there is a mandate in place for those interim targets that really isn't going to run into the PGC fund requirement for at least a few solicitations or at least for some time.

MR. JORDAN: What I heard this morning was we haven't had any solicitations, so we don't really know that. Apparently, I don't know this, but what one of the witnesses described was that

Edison has been paying below market rates.

We will buy all the renewables you want for below market.

PRESIDING MEMBER GEESMAN: why hasn't the City of Los Angeles figured that out?

MR. JORDAN: You know, I'm a little frustrated because you are not willing to make a recommendation for the state legislature to change the law, but you seem to be implying that we ought to change federal law in regards to coal plants.

PRESIDING MEMBER GEESMAN: No, I'm relying on local control and the good judgement of all Californians.

MR. JORDAN: I think that process works quite well in Los Angeles actually. I think people who have problems with their resource plan can talk to their city council and the city council is likely to fix it.

Getting back to the issue of mandate, you have a situation where the investor-owned utilities don't have sufficient resources, and so they have to procure resources. We didn't do that, we didn't sell off our resources. We suffered rolling blackouts, but it was because Edison and PG & E couldn't pay their bills. I

don't think you are talking about apples and apples here.

MR. TUTT: It's interesting to me that this morning we talked a little bit about re-calibrating utility targets depending on the circumstances of the IOU's, and there's not as many of them and their circumstances are probably more similar to each other than the POU's, but when we get into this discussion this afternoon, there is a lot of talk about diversity and applying different standards to different situations, so there is that connection potentially to this morning as well as to what comes next.

While the good people of Biggs and Trinity may not need any resources, if tradeable rec's are part of the picture, they presumably could spend a little bit more money if they wanted to, to green up the resources they already have.

MR. ARTHUR: I think that there is an issue here on economics that we need to be sensitive to and that is most of it, including I think the larger IOU's, are not in the business of actually building these resources, so we are very dependent on the development and expertise of

those parties that do build these.

The question is how are they going to price these. Obviously, they are going to price them at least at cost, but depending on the public programs we create, they may price them well above cost. What has yet to be seen is how they get priced, and I think Steve made a very good point this morning, we probably need some actual experiences so that we quit being hypothetical about what will happen and find out what really is happening.

Once we get that experience, we will find out how economic these opportunities are, and if they are very economic, I would expect to see a lot of development. If they are very uneconomic, we will probably have more rounds as we have a push back from those that have to pay it.

I think we don't want to create policies that result in unnecessarily high pricing.

MR. TUTT: I guess one last issue that I have on my mind, and it has to do with the hydro large and small. As Commissioner Geesman pointed out, there is state law that says 30 megawatts or less is eligible renewables.

There have been discussions, there is an

entity called the low impact hydro association, and I'm wondering if there might be room for some workshopping or discussion of that issue as we move forward. It seems like a reasonable thing on a staff level from my perspective.

MR. BEEBE: Yeah, there may be some good common ground to talk about that, especially after our relicensing is finished.

MR. GULIASI: I agree. This topic is ripe for discussion. Just to sort of add another element to it or point to it in terms of definition. We know what the statute says, and based on the judgement of the legislature, and then you get into other complicating issues like what counts as a facility or does a unit count.

If you look at a river system and a set of units equaling a facility, then they equal greater than 30 megawatts, and they won't be eligible.

If you look at it on a unit by unit basis, then for sure we would have a much larger portion of eligible hydro facilities or units counted toward that goal. So, I think we need to talk about those issues again.

MR. KELLY: I think that is just chasing

down a rabbit hole because as soon as you decide that large hydro stuff, which is 15 percent of whoever's load is going to count, then the rest of the world is going to say well, then we are going to raise the RPS another 15 percent. You can count it, but we still -- the people that push the RPS are really interested in getting some new stuff in.

They weren't interested in creating a structure that says we are going to count everything and go off and tell the world that we are just doing a great job. So, I'm not sure that solves your problem. The fight will show up in the legislature between the definition and we will spend years spinning our wheels.

MR. JORDAN: Is the public purpose here to encourage renewables or to encourage the people that wrote this definition?

MR. KELLY: I didn't write the definition, but I'm just saying the time spent on defining on whether or not this stuff should be including is going to be matched by time increasing the level so that there is no real effect.

MR. ARTHUR: I'd like to change that a

little bit. If I go back to my interpretation at least of the CEC's recent report that the core concern was that between the growth in the state and the retirements of some of the very old facilities, we are going to be in the very high price of natural gas, we are going to be very hard pressed to replace that stock in a cost effective way.

The conclusion was that renewables needed to at least be part of that strategy to do that. In that context then, whether we do or don't count large hydro may affect some of the overall levels, but it isn't going to change the fact that we need considerable new resource and at least part of that needs to be renewables.

I think that, at least from Redding's perspective, is what drives our strong acceptance of the general need for the development of renewables is, it is in order to meet requirements of the state going forward.

The large hydro issue is sort of an annoyance because its sort of artificial to distinguish hydro by its size when by the end of the day it is the same H2o, but setting that aside, we really do think we need to get a

diversified portfolio going forward to meet the needs of the state. At least my interpretation from some of the work that the state is more dependent on gas than most other states are, and that does create a vulnerability that needs to be addressed.

PRESIDING MEMBER GEESMAN: It is not just the high priced level, it is the volatility associated with that price.

MR. ARTHUR: Well, the volatility can be managed through allowing people to do proper forward market contracting, but the overall price is definitely an issue.

MR. TUTT: Good point. I had one question about Alameda. It is 55 percent eligible renewable right now, and it has a target in 2017 being at 40 percent?

MR. JORDAN: I noticed that same discrepancy. Since they are not here, I believe that probably has to do with the fact that the WAPA contracts are going away and some of their large hydro may be going away.

I don't know if John knows more about that than I do.

MR. BERLIN: It's just that it is tied

into hydro plus the geothermal output.

MR. BEEBE: I've noticed that it has been almost an hour since I had my last green house reduction advertisement. I thought I would note that the California Climate Action Registry, although it is voluntary, has set up a pretty good way of posting green house gas on the web.

The piece that I would like to bring in here is that a participant that gets into the public registry and goes through the whole process, actually has third party certification of that information.

It would be an easy step, I think to add to that whole concept the ability to get the third party certification of what is renewable or an eligible renewable against a list. That could be included in that very easily and virtually at no additional expense.

I don't think there is a need right now, the California Energy Commission certainly has good records. We have open records. There's no question at the moment of who has what I don't think, but at some time in the future, there may be questions of voracity and if that were to come about, this might be another cheap pathway that

doesn't require people being regulated or newly regulated kind of thing to have things verified.

MR. GULIASI: I'll just add one more point to the fray here. Let me say I don't disagree with Steve Kelly that by raising this definitional issue, you know, you necessarily then start chasing rabbits down a hole. I think that will be the consequence, and I think we will just find some gaming going on about what counts again and what the percentage goal is and that sort of thing.

There is a practical side to this question. Again, I think the distinction is artificial, and as an owner of a facility, you are faced with real investment decisions. Do you invest that dollar in you know refurbishing a dam or investing in equipment to already shut it down.

This whole question of what counts in the way of hydro speaks to the issue of resource adequacy. I really do believe that as you said the goal here is to stimulate more new renewables into the mix. There is no question about that.

At the same time, we have another issue which has to do with the adequacy of our resources. We want to make sure that we keep in

the mix cost effective and other renewable resources, hydro being chief among them.

MR TUTT: Okay.

MR. KELLY: I'd just like to end with that. I don't think there is anything in state law that says that any utility or load serving entity can't have 80 percent large hydro resource and a 20 percent RPS eligible resources.

The question is well, can you get it sited, can you get a permit, and all that kind of stuff. If it is a low cost resource, and it will fly on those merits. I don't see it necessarily incompatible with the load serving entities having large hydro within their mix.

The real question is are you going to count it against your RPS or not.

MR. BEEBE: This is a perfect time to note that those hydro resources at one time were horribly expensive. It took federal intervention and large public partnerships to be able to affect. If you want to try to do them again, you'd find out they are also very expensive because they are like other renewables. They require up front capital

The best resource in the world is that

one where the capital is all paid off and there is no fuel cost, but that sounds like a renewable resource to me, so I pledge that SMUD will maintain its coordination and its openness as we go forward in this context to put in the resources we need so that we will have the good cheap and environmentally benign resources in the future.

MR. ARTHUR: I would throw out to Steve and maybe the CEC could at least think about it is there may be some common ground here. One of the difficulties that wind for example has confronted in the resource adequacy workshops is that it doesn't get very much capacity credit because of its intermittent nature.

On the other hand, if you integrate wind with large hydro, you can overcome some of that. So, there may be some kind of hybrid product that we could come up with that could increase the value of wind and also recognize more explicitly the value of the large hydro as well. I don't have a specific recommendation, but I think there is certainly a potential linkage here that ought to be examined.

MR. TUTT: Thank you. Any further comments on the POU? I would propose we break and

come back in 15 minutes for the final one.

(Off the record.)

MR. TUTT: I want to remind everybody that in the workshop notice, that we said there would be an opportunity to file reply comments by May 10. If you are interested in what you've heard today and you have something to discuss further or add to, then May 10 is the date we would expect to get some reply comments from you all.

Coincidentally, May 10 is also a workshop here at the Energy Commission on transmission issues which will in part cover renewable transmission issues. So, that day has double significance, so keep that in mind.

Anybody coming forward for the Rec round table, please come up to the table and sit down. You can change your -- there is some extra name tags here if you want to get new name tags rather than being Jerry Jordan or Karl Knapp.

This portion of the round table here is to discuss the issue of rec's and in particular tradeable rec's. In the workshop notice that we sent out, we noted that the CPUC decision of last summer indicated that before we consider adoption

of a rec trading system, we need to carefully consider the issues involved there, whether a rec trading system would be consistent with the specific goals of SB 1078 and so on.

We've also identified in the workshop notice and in the presentation I gave this morning some peculiar or particular issues involving REC's and the RPS structure we have in California where we have a market price reference and the above market cost of renewables so to speak would be covered by supplemental energy payments to the extent they are available.

A rec could be described as a representation of the environmental attributes that is compensated for, and how do we talk about that compensation in terms of a market price reference structure.

Also, in California we provide public goods charge funds in various ways to renewables, supplemental energy payments, production incentives, even helping to buy down the cost of distributed photabletaic systems for example, and to what extent is that public fund contribution, funding contribution, addressed in the ownership of the subsequent rec's. Those kinds of issues we

need to address as we move forward in California.

I'm not going to start with you again, Bud.

MR. BEEBE: Good.

MR. TUTT: How about Manuel, do you guys have anything to say on these issues?

MR. ALVAREZ: Well, what I guess I would like to start off with is this a new area for us. I would like to introduce Frank Harris here. He has been looking at some of these issues as well. As we move along, we will enter into the debate.

I think there are a couple of issues that need to brought to the attention here of the committee, and that is you have an old system that was in place, and you've got a new system that you are creating. I think you have to be aware of both areas and how this is going to play in a rec market should it develop.

MR. TUTT: What do you mean by old and new system?

MR. ALVAREZ: There are renewables that are old contracts that we are still living with and they are a legacy system under old regime, and then there's the new project coming to the RPS that as you heard earlier today are still moving

forward on solicitation and I think you have to address that.

We have participated with work that the Energy Commission has done with the WREGIS activity. We have attended a couple of those meetings. There are a series of reports now that people are reviewing in terms of institution and operation that we haven't had a chance to react to, so we would like to reserve some judgement there.

Basically, that is about it. I think this is something new to have to deal with the Western states if you are going to do an out of state kind of program. Maybe Frank has a couple of items he wants to share with you and we will wait for the dialogue to continue.

MR. HARRIS: I'm fine for now.

MR. TUTT: Phil.

MR. RUDNICK: My name is Phil Rudnick. I'm here to represent a nascent wind energy company called Job Owned Energy.

We haven't yet developed a project, but we have a very very significant wind resource on a ranch that our family owns that consists of about 60,000 acres and may have and probably does

conservatively have something in excess of 500 megawatts of wind.

It needs to be developed, and it needs to be developed for all the reasons that I heard today, and I am here to learn, not so much to contribute, but I am here to learn what we can do and maybe some suggestions as to what may help this process.

One of the things that I learned today is there seems to be somewhat of an agreement that a rec, a renewable energy credit that has been established basically to encourage the development of renewable energy is considered a property right. I think that is a fair consideration.

Then I heard that the discussion had to do with well, should it go to the developer to off set risk, or it does it go to the end user, where does that reside.

My suggestion is that it ought to reside with the property owner if it is a property right. Doesn't the owner of the property or the land just like they own the wind resource, don't they own the renewable energy credit that goes with it?

The reason I say that is because in current day negotiation, these land owners,

ourselves included, don't have the sophistication of understanding what happens to this green energy after it lights up a light bulb then maybe offsets some other RPS requirements.

We don't know how to evaluate the resource that we have. I think that if that was considered as a separate distinct property right of the land owner just like the wind resource, then the land owner would at least be alerted to the fact that there is an issue of value that they can negotiate on. Where that goes, I can't tell you, but it seems to me that the dialogue is misplaced.

If we agree that it is a property right, then it ought to belong to the property owner. Then by contract it can go wherever it goes. So, I would encourage that interpretation, and maybe that can fit into this overall scheme.

The other thing is that I have spent a little bit of time in connection with the question of whether or not a renewable energy credit is going to be accepted for mandatory emission compliance with the noxious gasses, etc.

I know that is ongoing right now. My question is, is if that is something that is

supportive and helps in the development and increases the value to our state of renewable energy, then shouldn't we also be asking for that rec, so to speak, to be used in a mandatory market, which would increase the demand so that we are not just looking at using those to offset penalties that might come about for failure to comply with the RPS.

I don't know exactly where we are state-wide on that, but it seems to me that a renewable energy credit certainly ought, if it is available to offset an RPS requirement, for sure it ought to be available to offset mandatory emissions because it doesn't create the noxious gasses that we are trying to offset.

The purpose of my thinking regarding the tradeable credits was brought up earlier has to do with the assistance in developing financing and developing renewable projects. I think as land owners become more knowledgeable about the resource they have, they are going to become more interested in being involved rather than just passive royalty, receive a passive royalty payment.

In that respect, a tradeable rec would

assist the people that have the resource. It would assist them in generating interest in developing this process, this project, because they then could look forward to forward contracting with reference to their REC's and create more interest and bring in more people at the development stage rather than the half a dozen companies that are viable developers because they have a tax appetite.

I think there is a significant value to the rec basically to encouraging the development of renewables, especially in wind.

MR. GLADER: My name is Anders Glader, and I represent PPM Energy. We certainly don't have all the answers for all the questions that were including with respect to rec's, but I really just wanted to support the use of REC's within the RPS primarily because it provides some flexibility and actually goes to the heart I think of a little bit of the least cost/best fit situation.

As a wind developer, we hear from our customers very regularly the issues they have with taking an intermittent resource.

PPM has developed an expertise in handling that intermittent resource, but the

customer doesn't always want to see it. So, we have the capability of delivering a product that isn't necessarily intermittent that can be firmer in many different ways.

The problem is that means stripping the rec from the underlying energy and attaching it to another megawatt hour. At which at this point, as I read the guidelines and the rules, that wouldn't apply.

Under our rec trading system, I would imagine that would be very easy to see that would work. So, I see that by bringing in REC's into the RPS, making them eligible under the RPS, I see that you could basically broaden the market and that more customers would be willing to accept the types of products that we are looking to offer and also provide probably a more cost effective and better fit for many of the different customers.

I think you can also demonstrate for many of the small utilities that we were talking about, the Biggs or the Trinity, that they might be able to satisfy some of their RPS requirements in a more cost effective fashion if they could use some sort of a rec product.

Then there is the ESP's and the

Community Choice Aggregators. I think with respect especially with respect to the ESP's, you are going to have some difficulty finding many counter parties on either side that will be able to sign longer term contracts to make those entities satisfy their RPS requirements.

I think that the REC's incorporating REC's into the RPS program could work there too.

The last point, there is a question there with respect to in-state and out-of-state REC's and how that could work. I think our argument would be to deal with those in much the same fashion that you are dealing with the out-of-state energy itself when it is delivered.

If you are basically requiring the underlying energy would be delivered in the same way that any energy that would have been delivered that would satisfy the RPS requirements, then those REC's would be basically achieving the same goals environmentally and otherwise as if you were delivering just a straight energy, a green energy product.

I know that Roby Roberts of PPM has commented on this before, that within the recent eligibility guidebook that was put out, out-of-

state energy was required to be delivered in-state, and our position on that is that the way that electricity is delivered and traded within the State of California it is not always delivered to an in-state point. It is delivered to commonly used trading hubs, some of which are located outside of California, not always that distance hub, obviously there is only a couple of miles from the border of California.

There is Mead, there's Mona, there's Peevy. There are a lot of them that are not within California that are not commonly used.

I think you get to a point where some of the IOU's and some of our other counter parties are more than willing to accept energy being delivered at those points as are we. It may be the most cost effective way to deliver that energy or those REC's to that customer if both counter parties choose to do so.

So, that is it.

MR. TUTT: A clarifying question if I could, Anders.

MR. ANDERS: Sure.

MR. TUTT: In terms of an in-state delivery requirement for underlying energy, for

renewable energy, one kind of expects to see as you see delivered to some place in-state or in your interpretation to some trading hub. If you were just doing a rec, would it be associated with some other energy that was also delivered then in-state or to a trading hub?

MR. GLADER: I think you could actually see a situation -- I'd have to think about this a little bit, but you could actually see a situation where you would require the actual underlying energy to be delivered to a hub.

For example, let's say we had a Wyoming wind project that we could deliver very easily to Mona, if we could deliver that, we could deal with the risk of what was happening of basically putting that energy to market and taking those tags and stripping it and delivering to a customer.

Whether or not that was attached to a block of power so that it was a firm product or whether or not it was just delivered as a rec itself, I think that would be -- depending on what the customer wanted.

MR. TUTT: Okay.

MR. PROBYN: Steven Probyn, Clean Power.

I've already stated our position on REC's. Just one clarification on the in-state/out-of-state issue, other jurisdictions have resolved this by essentially looking if you will at a number of layers of statutory disposition. I mean, at the basic layer there is the T-Rec certificate which really certifies that a facility produced an hour's worth, megawatt hours, of power, usually identifies the facility, and that is the traded certificate. That is, if you will, the accounting level.

State practice, however, has defined the utilization of that certificate to satisfy compliance goals. For example, Massachusetts took the position which may or may not be constitutionally viable in the long term that out-of-state power, i.e. the rec does not demonstrate that the power was produced within the State of Massachusetts, does not qualify for its rec program, or its RPS program. Very simple, end of story.

Connecticut took a slightly different approach so far, although they are still, as I understand it, in hearings or various other legislative statutory deliberations on what

exactly the definition of rec is geographically, but have essentially defined that as being New England because really for technical reasons, they are comfortable that the NEPAL GIS provides the verification and the validity certification that they need for their program.

So, you've got different approaches. All I am saying is different approaches in different jurisdictions. I think really at that level, the policy level, you can define whatever you want.

The State of California has said deliverability is the definitional term, therefore, regardless of the T-Rec, the accounting layer, if your T-Rec is not connected to the California system, it doesn't qualify. I think that is a fairly simple kind of definitional characteristic and allows the trading rec system to actually expand over time.

You might start off with that definition, legislators might say, well, you know, actually, it would be a good idea if California utilities had access to more liquidity in terms of the rec market, so we are going to include WREGIS-based REC's. That is a scenario, a possibility,

but not a necessity.

I think it is up to legislators over time to evolve those definitions.

Finally, I am really acting as a set up man for Steven here in terms of the IEP's position on rec ownership. I think it is clear, the generator owns the property right of the rec. That is what we are hearing from FERC, and it is a major court of competent jurisdiction in that regard, and it has reaffirmed that decision.

I think that is the first clear kind of legal principle. The second is double counting is an issue of public policy. We recognize that. We are not in favor of solutions that involve double counting. Having said that, I am actually going to hand it over to Steven who can more better explain or can better explain, forgive me, the nuances of our position. It is a heavy load.

MR. KELLY: More better blues there. Thank you.

Let me approach this in two ways and say IEP and the renewable industry which I represent which is a broad broad group of people across all technologies look at the rec concept as a good thing to pursue.

We also do see it as a property value and we are a little surprised to see in Tim's list of when he asked the question who owns the REC's, he indicated the public, the ratepayers, or the private purchasers. We think the better question is, who owns the rec initially. That is in our view the generator that created the rec.

It speaks for a couple of things. It really speaks for the need in an RPS program for a clear definition of what that rec is because if it is a property value and it is being conveyed from one person to another, from a buyer to a seller, in order to properly value that property, we need to have a good definition of that.

I know when the legislature in SB 1478, they were talking about all environmental attributes as conveyed in this rec. I've raised the question, and I believe it is a good one to say well, what happens if a wind farm owner receives an environmental payment for an environmental easement across his property to get to a vernal pool. Is that an environmental attribute that is associated with generation. Is that money supposed to be conveyed to the purchaser for RPS compliance? I'd say no.

We need to work on fine tuning on what the definition is, and that work is actually going on at the PUC as we speak.

The other important thing that the industry supports and is focused on is what Steven was talking about was the recognition that for this program to work, there cannot be double counting. Not only within California, but across the western region.

That will undermine public confidence in what the rec means and represents, so we are strongly for that. Having said that, I will make an observation that I think is missed in some of the debate. It is not the generator who created the rec. The generator who created the rec is not the one who is doing the double counting.

The double counting is occurring at the load side when they are using it for compliance for RPS. So, we support a rule that says there is no double counting. We don't think it is the generators that are double counting.

We are producing it once and selling it to somebody once, and then they've got it, and they are going to do what they want with it. It is the load that needs to be reminded not to

double count something that is being delivered to somebody else.

I think it would be very helpful if this commission would step up at the Western Governor's Association level and articulate the need for that group to endorse a principle of no double counting across the West to give the consumers some comfort that when they buy a rec, they are buying it and is not being used or applied against retail load at any other place within the western region.

That is something I think would be very important for you all to do in the context of the development of the WREGIS program and certainly in the context of developing something in California.

PRESIDING MEMBER GEESMAN: Would the way to do that be to simply roll it in as a self-enforcing requirement of WREGIS?

MR. KELLY: I think that is the way to do it. Ultimately, it is the regulators within the state agencies that are verifying compliance that have to say we are going to count that or not. So, you have 15 states or whatever it is for the investor-owned utilities anyway. We really need that group of people to step up and say as a policy or principle, this is what we are going to

impose on the people, the load serving entities for compliance purposes.

Hopefully, they follow through with that. Certainly, generators are not in a position to police that. It is really the regulators that need to do that.

PRESIDING MEMBER GEESMAN: Do you have any reason to believe that won't be a feature of WREGIS?

MR. KELLY: No, but what is missing and has popped up in discussion about some of the legislation here in California was the lack that certainly that would happen. I think this agency is perfectly poised to lead the charge on that, to get that standard in place as quickly as possible.

It raises an issue, and I will speak to an issue that Manuel brought up about how do you integrate this rec's trading program into the present environment where we've got what I will call these old contracts that were silent on this issue and the development of new contracts, RPS contracts, where one of the standard terms and conditions is going to address the definition of the renewable attributes that will be conveyed to the purchaser of the RPS contract.

So, for future contracts, RPS contracts, I don't really think this is an issue because the issue of ownership will start with the generator, it is going to be conveyed as a standard term of the contract to the utility in California.

It only comes up to be an interesting issue when you talk about what do we do with the existing contract holders. The contracts of which we are delivering energy capacity to the utilities under PURPA and FERC has clearly said that if the contract in that specify that there is an environmental attribute being transferred, it was not. We agree with that.

What we need to do, though, is to figure out a way because the way the RPS is structured is to recognize the intrinsic ownership of the rec, the environmental attribute at the generation, but recognize also that the utilities will count the power that is coming under the standard offer contracts against their RPS obligations. They don't necessarily have to own the rec to do that.

The regulatory agencies can simply count that power for purposes of RPS compliance. In that environment, the utilities meet their RPS obligation under the existing contracts that

qualify, the generator gets to retain the integrity of the ownership of the rec for its purposes.

If you have a policy of no double counting in the western grid, it may be that there is no place that they can actually move that rec, but they've got the rec and the integrity of that principle.

I think that vision what I call of how to do this, the more that I think about it, solves some of the potential litigation that would arise if there was an attempt to assume that the rec is being owned by the utility that is buying existing standard offer contracts.

I have a concern that the litigation that will derive from that will be long lasting, it will live way beyond the term, the existing term of the contracts, and will have the tendency of destablizing the WREGIS program because you are going to have uncertainty as to who is able to participate in the WREGIS mechanism. One of the principles that WREGIS is trying to develop I think is that it is the people that start there before they transfer it to anybody else, are the ones who own it.

There is general recognition that we have to account, though, for this block of power that the utilities are purchasing and are arguably should be counted against the RPS requirement.

PRESIDING MEMBER GEESMAN: Now the FERC decision as I understand it did contain the provision that as long as state law was consistent with FERC's interpretation, so I guess there is arguably logic that because California law is in the past has been seen to be confiscatory in some situations that a confiscation of that rec would be appropriate here.

I have a hard time accepting that logic.

MR. KELLY: I don't agree with that interpretation of the FERC decision. I don't think there is anything, certainly going forward, they said state law can't prescribe what is going happen to these environmental attributes, and we are doing that.

I don't think FERC said, oh, by the way, the state can step in and retroactively assume or take that property. It is really no different in my view, since it is a property value, that the state were to step in and say through legislation, say, Oh, by the way, you holders of these

contracts, we own the turbines too, we own the boilers from the biomass facility that we paid for, for the last fifteen years under these contracts.

I don't think anybody believes that would pass a legal test, and I don't see the REC's being any different because they are being defined as a property value. As I say, I am trying to craft the mechanism that avoids the litigation, allows us to further develop, retains what I believe is the proper standard that the generators retain the property right to begin with initially. Then they sell it or transfer it to somebody else as they will.

PRESIDING MEMBER GEESMAN: As it relates to the existing contracts, in almost every circumstance we are talking about QF's aren't we?

MR. KELLY: I believe so.

PRESIDING MEMBER GEESMAN: So, they are all subject to standard offer contracts and --

MR. KELLY: Yeah, and in all those contracts when you look at them and this issue about environmental attributes comes up, you have to recognize that this same contract was applied to the gas fire co-generators as applied to the

renewable entities.

PRESIDING MEMBER GEESMAN: There is no special price premium paid to the renewable guy for whatever renewable elements may have been associated with his contract.

MR. KELLY: The price premiums usually came based on the firmness of the capacity as available capacity versus firm capacity. The price premium -- they all I think were equally eligible for the fixed price period for the energy.

There were four different contract structures. Some technologies fit better into one type of contract versus the other. I'm not exactly certain whether they were prohibited from at the same time period in time from exercising one or the other that they chose, that they had a choice at that time.

Over time, those choices were narrowed, and now we are in to where there is only a standard offer one contract that is available for all QF's.

MR. MASRI: My recollection of this issue for the accuracy of the record, Steven, is I believe the gas fire co-generator will not allow

to elect the fixed prices for energy. Okay, it is only for renewables.

You have a fixed heat rate, but the prices fluctuate as gas prices fluctuate. It was done for their own protection because the fuel prices go up, but they had the fixed revenue they could be in trouble. So, really the fixed energy price was a renewable QF only option.

MR. KELLY: I'll have to go back. It has been a while since I have gone back and looked at those contracts in this context.

PRESIDING MEMBER GEESMAN: Is there any argument, Marwan, that particular contractual feature was somehow compensation for an environmental attribute or was a proxy for compensation?

MR. MARSI: It has been a while, but renewables as we all know, in those years, were new technologies most of them and perceived to be risky and so on. The fixed revenue was meant to allow the (indiscernible) to financing.

Obviously, they were considered to be preferable resources, policy wise. Encouraging them was part of the attributes. I don't think it was explicitly stated anywhere that we are paying

this extra money for these attributes, but the understanding was they have benefits, and therefore, they were worthy of special treatment.

Those contracts were specially targeted to renewables.

MR. KELLY: I think the other piece of that was those six price terms that had that high number was also recognition of the high fixed capital costs of the asset, and there was front loading going on there essentially too.

MR. MASRI: It is interesting to add that the renewable project could choose between a fixed energy priced contract or a fluctuating standing offer one contract. In those years, some actually elected the stand offer one contract, believing in those years that gas prices and fossil pricing would be going up to the higher rate, and therefore it would be better off than even the fixed prices.

PRESIDING MEMBER GEESMAN: Usually the courts would want to know what the parties originally intended. Did they intend to transfer some at that time to --

MR. KELLY: I don't think this concept was around.

MR. TUTT: I agree, I don't think that is part of the issue is the concept wasn't around back then.

PRESIDING MEMBER GEESMAN: Well, but I think that may be the issue, then, if it wasn't around, how could you sell it?

MR. KELLY: That is where I think they would likely end up. I have talked to some of the folks who negotiated some of those contracts, I wasn't actually around when that happened. When you look at the terms of the contract, it talks about the delivery of energy and the delivery of capacity, and those are the pricing terms.

PRESIDING MEMBER GEESMAN: I'm sure there is a competing viewpoint, does anyone want to offer it?

MR ALVAREZ: The only thing I will offer, Commissioner, is I guess at the time of those contracts, there was a lot of discussion about the recognition that the renewable projects who were receiving these contracts were in fact providing benefits to the State of California, so Steve cautioned the issue of litigation over the next years depending on where this thing takes us.

There are policy documents that

recognize those attributes and findings and moving forward on the contracts that had renewable components to them. So, it is one of these questions when we deal with is there contractual legal requirement, or was the policy of benefits from renewable already identified and therefore presumed to be part of the contract.

MR. KELLY: Yeah. I can almost guarantee you that this issue is sufficiently important on a regional if not national scale that will take some time to resolve it. One of my interests is to avoid that.

PRESIDING MEMBER GEESMAN: Yeah, but didn't FERC take an awfully large step in the direction of resolving it?

MR. KELLY: Well, we've still got a debate apparently about what FERC said in that order. Even in response to the request for clarification, I think they were fairly clear that said if it was not conveyed in -- if this environmental attribute was not conveyed in the contract, it wasn't, and then they go on to speak about if the state wants to do that, they could have or could going forward.

There is likely -- I think there is a

way to avoid the litigation. I recognize that the utilities who have had these contracts should be counting them against their RPS obligation. That allows them to be made whole, and if nobody else can count them, certainly in California we have the opportunity to make that clear if it isn't already clear. Then the demand for them is going to be (indiscernible) at best for some time as we transition out of these contracts.

I will just point out that this may be just simply a transitional problem. A huge percentage of these contracts are going to be terminated within the next three to six years.

PRESIDING MEMBER GEESMAN: The PUC has encouraged the utilities to enter in to new contracts with the QF's, haven't they?

MR. KELLY: That issue will be clarified in those new contracts when they come off. You will see that like I said the litigation is likely to extend beyond the period of the contract term.

MR. TUTT: It sounds to me, Steve, like the proposal that you are suggesting is that the utilities count the energy as part of their base line. The QF's retain the REC's, but by law or policy, they can't do anything with them.

MR. KELLY: They can do whatever they can with them if there is anything to be done with them.

MR. TUTT: Well, whatever they can with them is double counting typically, so --

MR. KELLY: No, that's my point, though. My observation is that it is only the load that is double counting.

MR. TUTT: I'm a little interested in the clean slate you give the generator there. If the generator sells energy and attributes to one load serving entity, and then sells the REC's to another entity, and that other load believes that they are buying REC's that haven't been counted elsewhere, whose fault is it? Is it the loads fault or is it the generators fault?

MR. PROBYN: There's misrepresentation.

MR. TUTT: By the generator, and that is where the double counting comes in.

MR. PROBYN: That's misrepresentation. Obviously, misrepresentation is civilably actionable.

MR. KELLY: Oh.

MR. PROBYN: Well, if you are misrepresenting your product, then you face a

claim by the buyer. If you've said to the buyer of the product, oh, these REC's haven't been used anywhere, they are not part of -- because the buyers are going to say, well, is this part of utility compliance. You say, well, no. Then you are making a misrepresentation. That is quite clear.

MR. TUTT: What if the buyer doesn't ask the question, but the generator knows?

MR. PROBYN: I mean, the buyer should ask the question, but my point I think is a little bit more broad-based than that because essentially the generator, by maintaining the ownership of the rec, and in the circumstances that Steven has described, really not having an opportunity to sell it will maintain the ownership of the rec following the expiring of the contract.

At that point, that generator will then own the rec free and clear in effect and will be able to recontract with the utility. At that point, the utility will undoubtedly insist that the rec is included in the overall contract price. So, you know, over time is sort of self rectifying.

MR. KELLY: I think this issue about who

is double counting, the WREGIS system is up and operational as being contemplated, there is going to be sufficient information for certainly all of the regulatory agencies to be able to say we won't allow this to be counted for purposes of RPS compliance because of this, the deliverability requirement, gee, it looks to me like you've already made a commitment.

This is a standard offer contract in California that is being sold to "X" utility, therefore, we are not going to count it because they are counting it. That information will be broadly known, so I don't -- if you are asking me if the regulatory agencies who are insuring compliance on this stuff are going to be asleep at the wheel, I don't think this is going to happen. Certainly this agency wouldn't do that. I doubt it would happen in any other agency.

MR. TUTT: I hope that is the case, I certainly believe that's the case. I guess my question is if you are talking about setting up a situation where the utilities would count their base line energy as complying with the RPS, meaning we are counting it as renewable, but the generator continues to keep title to the rec, it

almost sounds like you are setting up a temptation then to do something else with that rec which might end up being called double counting when the regulators wake up to the fact.

PRESIDING MEMBER GEESMAN: Let's say to follow on to the example it is used for some non-RPS purpose. You sell it to an air district, you sell to the World Conference of Churches, you sell it to a coal developer in China, would that create a problem?

MR. KELLY: I think, no. If the coal developer in China wants to buy this certificate from somebody who has got a generation site located in California who is selling energy and capacity to a utility there, fine. I can't imagine why they would do that, but we can do all sorts of hypotheticals, and this is why I am urging this commission to go to the Western Governor's Association to articulate this issue about double counting because I think that is where it is happening there.

PRESIDING MEMBER GEESMAN: Yeah, but we are looking at double counting for RPS purposes. I don't think we've broadened it really beyond that.

MR. ALVAREZ: This is an issue that surfaces in the WREGIS discussion because it gets to the definition of the rec in terms of what attributes are being conveyed in this transaction. I don't think we've actually gotten to a definition yet that is even put out for discussion or consideration by a public body yet.

MR. KELLY: Well, the PUC --

PRESIDING MEMBER GEESMAN: I just raised a fundamental one, is the rec representative of the kilowatt of installed capacity or the kilowatt hour of energy that comes from the capacity.

MR. GLADER: I work for PPM Energy, I used to work for Green Mountain. My understanding is the rec has always been attached to the megawatt hour or the kilowatt hour. My argument -- I'm not an attorney, but historically, the utilities have always been using this or declaring wind energy and using it in their power content labels if I am not mistaken.

For example, they might say they have 17 percent, there is some wind energy in there that is going to come from their SFO contracts. What differentiates that energy from any other undifferentiated energy is affectively the rec,

even if it was stated as a rec or not. I would say historically, they have had rights to it, and now all of the sudden it is an issue.

I don't know if it is a grandfather thing for lawyers that they can tackle that, but there is something there.

PRESIDING MEMBER GEESMAN: If you were an attorney, you would say they had stolen it historically, and they ought to be sued.

MR. KELLY: That is what my attorney is telling me.

PRESIDING MEMBER GEESMAN: Dan, why don't we hear from you.

MR. SCHOCHET: I can share with you the Nevada experience since we are a smaller state, we have a lot less inertial than California, so we've moved ahead on this.

First of all, the rec in Nevada has been defined as the difference in the cost of the renewable energy on a kilowatt hour basis. There is another definition that is being used called the environmental attribute, so that in the current power sales agreements that are issued under the RPS in Nevada, you are assigned to the utility the energy generated, the rec, and any

environmental attributes, and then there is a side deal regarding what happens if the PTC takes place, the production tax credit.

Now, the rule making in Nevada is such that No. 1, existing contracts, since Nevada doesn't have a public benefit charge, it was assumed that the rec was the premium paid for renewable energy on existing contracts as well.

The only REC's that are now being assigned to the generator are the station used REC's. The REC's that tag along with the generated energy are the property of the utility, the purchaser, and he gets that along with his energy as part of meeting his RPS.

On existing contracts, the stationed used REC's can be resold, and I will tell you a bit about that in a moment.

The rule making was such that there was one rec per kilowatt hour. However, to encourage small solar for rooftop solar systems, they actually allow 2.4 REC's per kilowatt hour, so this becomes an incentive for the homeowner to install it, and an incentive for the utility to purchase any additional power through the bilateral two-way metering.

The value for a rec is different for the different technologies, and I am most familiar with geothermal. In the case of the geothermal, since all the geothermal energy is in the north, and the bulk of the power, two thirds of the power used in Nevada is in the south, the power sales agreements we sign actually were signed on the basis of a back to back agreement between Sierra Pacific and Nevada Power, so that Nevada Power is the purchasing utility, but the energy is being stripped out and that goes to Sierra Pacific and then the rec then is going to Nevada Power to meet their RPS requirements.

To assign a value to the rec, the Nevada RPS rule has penalties for the utility that doesn't meet its RPS requirements. There was some discussion and there was even an open auction, and since I am in the middle of some negotiations, and I'm bound by confidentiality agreement, I can tell you though that my personal opinion and what I use is that a rec in today's world for geothermal is about 1/2 cent per kilowatt hour.

That has been more or less recognized as a market value. This represents the value averaged over the life of a five year contract for

the difference between let's say the fossil fuel purchase and the geothermal purchase.

In order to purchase a rec, the utility would have to purchase the rec from a generator either in its service territory or a generator connected to its service territory.

Now, I haven't gotten into yet what would happen with some of my fellow operators in Nevada who have geothermal power generated in Nevada and they are selling it to Southern Cal Edison. I don't know, and they do have station used REC's that they would be entitled to sell. I don't know where that stands, I haven't discussed that with them.

This policy seems to work because in fact in order to achieve this, the back to back power agreements that we have with Sierra Pacific were not only approved by the Nevada Public Utility Commission but the agreement that tied the REC's from Sierra Pacific to Nevada Power was also approved by FERC.

This seems to be an equitable approach. The utility is obviously paying some premium for the power, and that premium is represented by the rec. It appears to be equitable enough that none

of us in Nevada are threatening to sue the utilities at this point. So, I thought I would share that with this audience, and I am a member of the IEP, so I do ascribe to the IEP's position.

In Nevada this seems to be working quite well and hasn't been a bone of contention at all.

PRESIDING MEMBER GEESMAN: Well, as you know in California we enjoy suing each other, so maybe it is a different standard here.

Bud.

MR. BEEBE: Let me say that SMUD is actively engaged in the WREGIS forum and there is a lot to be learned there, and I think we all would benefit by keeping close tabs on that and other forums to do with these renewable energy credits.

At its base, we at SMUD want renewable energy credits to facilitate new and existing renewables and not just to be a windfall, so that is the serious business of this thing I think. We have some experience with renewable energy credits or by another name, green energy credits or green tags, and have spent quite a bit of time since our greenergy program was introduced in 1997 thinking about them and working with them or working

against them.

We have something that I would like to sort of share with you. One of those things is that disembodied REC's, that is renewable energy credits that are totally disassociated from energy flow of any sort are really best used as a secondary market to facilitate the primary market transaction.

They are not a substitute for a primary market, and if you get the secondary market ahead of the primary market, things just don't work well at all, so let's just establish a good primary market for new renewables and get on with the RPS thing.

As these other forums, like the WREGIS forum, define REC's better, we can figure out how best to use them to facilitate these primary markets that are going to be needed to bring in lots and lots of renewable energy.

I've got three points I really want to make, though. They are not all like connected to each other.

The first is that for some years now, ten plus one, in fact, there's been something that public power has been concerned with, and it is

called the renewable portfolio standard, which at the federal level is an incentive for publicly-owned utilities to operate renewable generation resources.

It is a nominal penny and a half escalated on each kilowatt hour of --

MR. TUTT: Production tax credit.

MR. BEEBE: Pardon?

MR. TUTT: A production tax credit?

MR. BEEBE: No, it is a renewable production incentive, so for publicly-owned utilities only. This was to level the playing field against the tax incentives, the tax based incentives that are available to private parties. That was the idea.

In fact, what happened is that congress never fully funded that program, so it was chronically under funded. We are not talking like three quarters of the funding or half the funding, but it is typically like one tenth of the funding, so there was always this great scramble for the small cash that was associated with the RPS, excuse me, with the renewable portfolio standard --

MR. KELLY: Renewable production

incentive.

MR. BEEBE: Renewable production incentive, thank you very much. The problem was that there was so little faith that congress would appropriate enough money for this thing that instead of it really facilitating and encouraging new projects, it was simply a windfall for those who happen to be in at the right time and if there was any money there.

In other words, when you were getting ready to sign a project, you gave zero benefit for this thing. On the other side, if it did come through, well, that was some cash. That is the wrong way for public policy. To correct that, we have worked hard on a number of different ways that whole program could be constructed to get rid of that problem, and let me just mention this one specifically because it is currently in the tax bill, in the foreign tax bill that used to be in part of the energy bill, but now it is in the foreign tax bill. I think you understand where that is right now.

If passed, it will allow publicly-owned utilities to have tradeable tax credits which means that if we participate in developing a

renewable facility, then the energy that is made from that, we can take the credits from that and reassign them or sell them to other people. That is a great way out of the problems we have with the under funding and so far.

The extremely different way that publicly-owned utilities were remunerated by the federal government for their renewable energy as compared to private entities. So, we want this to pass, we hope it does pass. We hope that maybe not in this congress, in a future congress, someplace we are going to get this done. We would want not the RPS REC's or other attributes that might go with a renewable energy credit to be confused with the tradeable tax credits that we could accrue from this newly minted legislation should it pass. That is one item.

Secondly, this brings forward the need to assure in your REC's that you really know what is in a rec. For instance, not all renewables are equal. For instance, photabletaics are not the same really as biomass and that is not the same as say geothermal.

These may have different market values, they may also have different liabilities

associated with them. I mean when you get the renewable energy credit, do you also get future litigation associated with some attribute of that thing. You really have to think through this stuff pretty clearly before you decide what is in a rec or what is not in a rec. So, that's an item.

Thirdly, and this stems mostly from my days when I was doing the greenergy thing, and that is it always galled me that renewable energy was burdened with the necessity of having to create, to market, to keep track of their renewable energy credits, while brown energy was not burdened with this stuff.

Maybe we would all be better off if everybody had to identify what kind of energy they were producing and the principle attributes of that, environmental and otherwise. That those attributes should carry through with the energy sale and be followed by that. If they are split off and sold separately, that transaction could be similarly followed.

If you made everybody identify all those things, it would get rid of one big problem, and that is people distrust this renewable energy

credits because they think they are hiding some sort of like fossil energy or non-renewable thing.

If the non-renewable credit is also identified, it gets rid of that difficulty with voracity.

Let me just close by saying that SMUD will remain engaged in these, the WREGIS process and others that we know exist, and we will endeavor to find the right place in the forum for renewable energy credits and where these renewable energy credits are used, we will employ them in the spirit of assuring that they facilitate and truly represent energy that we have purchased.

I'll close on just a personal suggestion. I think that everybody who has an opportunity should sell a renewable energy credit or two. I think you would learn a lot about what an renewable energy credit is if you sold one and lived with the consequences. Thank you.

PRESIDING MEMBER GEESMAN: Joe.

MR. KLOBERDANZ: It sounded a little scary there at the end.

MR. BEEBE: It is.

MR. KLOBERDANZ: I can't contribute much to this rather detailed discussion. I will say

that the solution Steven Kelly was laying earlier is something we have been discussing with him, and we are certainly considering how to deal with that difficult issue area. We haven't come to final conclusions yet.

I would just observe for SDG & E in particular, it may become very important that we have a rec system, a rec trading system, that the CPUC will allow to count towards the RPS requirements.

In that regard, the WREGIS work that is going on seems to be well directed and well headed toward something that would support a trading system that the Public Utilities Commission can get behind. We appreciate the Energy Commission's work to get things as far as they have, and we hope they will see that through.

At this point, some of the questions in the document, the hearing document today, had to do with PGC funds and MPR for REC's. We think it is important to get a trading system out there and work with it for a while and then look at that later.

I am not sure how to solve that problem, and I'm not sure it is a problem we have to solve.

We ought to get the system out there and up and running and see how it works for a year or two and see if it produces the kinds of fairness, the kinds of equity, and the kinds of solutions to meeting the RPS that we all hope it will.

That is all I have, thank you.

PRESIDING MEMBER GEESMAN: Now, did I understand you to suggest that one of the reasons why REC's are likely to be an important aspect of your meeting the RPS goals is the fact that the state has in its wisdom or lack thereof left you fairly land locked from a transmission access standpoint?

MR. KLOBERDANZ: It is the uncertainty that the current situation in the state for licensing transmission, and the uncertainty in our particular service area about in-system resources in combination leaves us with enough uncertainty that we would like to have an option out there. We would like to comply.

Thank you.

PRESIDING MEMBER GEESMAN: Okay, I understand. Where do we go from here?

MR. TUTT: If there are no final comments by anybody, remember that reply comments

are due on May 10, and we will take all of the information we got today and the original comments filed last Friday and on May 10, and we will be melding that into a staff white paper, I believe, that comes out in a couple of months.

PRESIDING MEMBER GEESMAN: Phil, I think you had another comment.

MR. RUDNICK: Yeah, if I can have an opportunity, you know, I am really encouraged from what I've heard here today, but there is one area that I would like to put on the record and maybe have these other people think about. That is, all we've talked about today is what we are going to do with this renewable energy once we create it, but we haven't talked about the time lapse, the time that it takes to develop a wind energy resource.

We've got assessment time that could be two and three years in order to get sufficient wind data. We have permitting time that could take another two or three years depending on local NIMBY opposition to the project.

It seems to me that one of the things that we ought to think about and see if there's a way we could encourage something that would be in

the nature of having the state preempt this area of permitting that basically says land that is zoned "A" for agriculture is suitable and can be used for the harvesting of the wind resource, just like they harvest the grass with their cattle or the corn in their farming.

It is just another resource that goes with the land, and they shouldn't have to go to all the expense of having to convince local authorities that this wind resource needs to be developed because the problem we run into is that people who are accustomed to trespassing on the land owners view shed some how become convinced they have a prescriptive right to that view.

Because there are a lot more local people, their votes count a lot more to local supervisors. Then it creates all kind of uncertainty and difficulties which could be overcome if we could get some state preemption in that area.

The other thing having to do with that is the fact there ought to be some consideration I would suggest to the current owners of all the renewable wind resource property in the State of California. Those are the people who are the

ranchers primarily. They are not downtown Los Angeles or Sacramento or in the outskirts in an urban area.

There ought to be something we can do to encourage those people to go out and initiate some assessment activities so that you don't wait for some developer to come knocking on the door and then you have to wait another three or four years or five years to get a project up and running.

I would suggest that some kind of incentive to encourage those landowners who believe they have a viable wind resource to go out and establish relationships with the meteorologists to put up some anemometers to get the data that is necessary, that will help this entire project of accelerating RPS, at least in wind.

I think you are talking about saving three or four years from an average project, very significant. If we can do that coupled with all the things that we have talked about here, we will not only meet the RPS commitment, we will surpass it, and we will be talking about a substantially higher RPS goal thereafter.

PRESIDING MEMBER GEESMAN: Are there any

other public comments?

COMMISSIONER BOYD: I'd like to make a comment. Bud, I'm disappointed you didn't say climate change in this last -- I've been keeping track, I've got three tic marks here next to your name. I'm sorry your municipal friends have left, but you did mention the climate change registry, and you didn't openly solicit an advertisement. But I would comment in this public forum that SMUD was the very first agency in the State of California to get certified by the climate registry, so you deserve some appreciation for that from those of us who follow the subject very closely. So, anyway, and the gentleman who said sustainability is gone already, so I can't give him any kudos either.

MR. BEEBE: Thank you very much, Commissioner Boyd. It is the kind of down in the trenches work that needs to be done, and all of the people around this table an others who have been here work hard at making electricity affordable and environmentally acceptable. So, just one of our pieces we do.

PRESIDING MEMBER GEESMAN: Well, I'd like to thank each of you for participating today,

as well as the panelists who were here earlier and certainly you, Tim, and Marwan, your staff for organizing a very productive today. I think we are going to learn a lot as we review this transcript and also the written comments.

We will be adjourned.

(Whereupon, at 4:44 p.m., the workshop was adjourned.)

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CERTIFICATE OF REPORTER

I, ALAN MEADE, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Workshop; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said workshop, nor in any way interested in outcome of said workshop.

IN WITNESS WHEREOF, I have hereunto set my hand this 14th day of May, 2004.

Alan Meade